NRRI-79-1

ENERGY MANAGEMENT AND CONSERVATION THROUGH PRICING INNOVATION IN WISCONSIN

A Case Study

Prepared by

The National Regulatory Research Institute

with the Cooperation of the

Wisconsin Public Service Commission

January 1979

ACKNOWLEDGEMENTS

This case study was prepared by The National Regulatory Research Institute under Contract No. EC-77-01-8683 with the U.S. Department of Energy, Economic Regulatory Administration, Division of Regulatory Assistance.

The authors of the case study, Kenneth Pearlman and Patricia Stach of the National Regulatory Research Institute, and Alvin Kaufman and Russell M. Profozich, economic consultants, appreciate the assistance and cooperation of the commissioners and staff of the Wisconsin Public Service Commission. In addition the case study benefited from the review and comment of Robert M. Stronach, U.S. Department of Energy.

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The National Regulatory Research Institute appreciates the cooperation of the Wisconsin Public Service Commission in the release of this case study for the use of other parties, especially those state regulatory commissions which may benefit from the Wisconsin experience.

EXECUTIVE SUMMARY

In the fall of 1977 and winter of 1978, The National Regulatory Research Institute (NRRI) conducted a survey of state public utility commissions for the purpose of identifying energy management and conservation programs that could serve as potential case studies. The purpose of the case studies is to provide public utility commissions in one state with information on how commissions in other states have handled energy related problems and instituted programs to cope with such problems.

On the basis of nine criteria identified by NRRI, five case studies were selected. The appropriate state utility commissions were then contacted and their participation was arranged.

Wisconsin was chosen as one of the five case studies because of the activities of the Wisconsin Public Service Commission in the sphere of electric rate design. Over a period of several years the Wisconsin PSC has been moving toward time-of-day (TOD) pricing for electric service. This has involved increasing the number of customers on TOD pricing, evolving more elaborate methods for resolving TOD problems, and, in general, dealing with TOD issues in an increasingly sophisticated fashion. Although the decisions issued have generally been in the theme of TOD pricing, the intent of this policy has been to make the cost of service to the customer more closely related to the utility's cost of providing that service and, by sending proper price signals to customers of all classes, to reduce overall system demand.

Most of the activities of the Wisconsin PSC occurred through decisions and orders in specific rate request procedures. The PSC also conducted a generic environmental impact investigation to assess the impacts of changes in rate structure. This case study thus focuses on the major rate cases involved and on the environmental process.

This case study shows how the Wisconsin Public Service Commission has moved forward in a direct and orderly manner in the institution of time-of-day pricing. Careful study has been done by the Wisconsin Commission on the various economic considerations of this policy change. However, more work remains in other relevant areas, such as socio-economic effects and environmental impacts.

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Background and Purpose of Case Study

Background

During the fall of 1977 and winter 1978, members of the staff of The National Regulatory Research Institute (NRRI) conducted a series of visits to state public utilities commissions. The purpose of these visits was to obtain information about utility energy conservation programs in effect in various parts of the nation with the intent of formulating a report of such programs which could be distributed to other states.

Accordingly, NRRI staff contacted and interviewed members of state public utility commissions, state energy offices and staffs of nonregulated municipal utilities. Attention was focused on electric utility rate reform, gas utility rate reform, residential energy conservation, district heating and utility operating efficiency. Detailed information was solicited from those agencies indicating involvement in any of these types of activities.

Eventually, NRRI identified 66 such programs or policies, which were then judged according to nine criteria, including extent of innovation, extent of multiple institutional involvement, impact on energy savings, state of program development, availability of required skills, transferability to other jurisdictions, availability of data, support of potential host agency and time required to complete the case study. From the initial list of 66 candidates, five case studies were chosen.

Two of the case studies, Wisconsin and Missouri, involved electric rate reform. The areas of gas pipeline leakage, energy management and residential conservation were represented by one case study each in Arizona, Arkansas and Oregon respectively. Utility commissions in all five states agreed to participate in the case study process.

Purpose

The purpose of this case study (and of the other four) is to provide state utility commissions and nonregulated utilities with information which will lead to energy conservation and more efficient energy management. It is hoped that information of a practical nature on the process one jurisdiction has used to cope with a specific energy-related problem will assist others in tackling similar problems. Accordingly, the focus of each of these studies is the process involved.

This case study on Wisconsin time-of-day (TOD) pricing for electricity provides a detailed description of the major rate cases involved in establishing this policy. It also provides information on the structure of the electric utility industry and the nature of electricity generation, as well as information on the major parties involved. The Wisconsin Environmental Protection Act, which affected the Commission in its decisions, is also considered.

Reform through rate request hearings and orders is a process available to other state utility commissions. The information in this study is intended to be an illustration of the application of that process.

Methodology

As indicated earlier, the Wisconsin case study was one of five chosen on the basis of nine specific criteria. Information obtained during the initial interview and selection process, as well as from an early on-site visit by an NRRI staff member, indicated that rate hearings and Commission orders played a major role in the move to time-of-day pricing in Wisconsin. As with all the case studies, a liaison person was designated in the Wisconsin Public Service Commission to aid in scheduling interviews and obtaining documents.

NRRI case study researchers, with the assistance of consulting economists, conducted a detailed analysis of relevant rate case hearings and orders. Interviews were also conducted with staff members of the Wisconsin Public Service Commission, as well as with representatives of the two major environmental groups instrumental in generating major policy changes out of a routine rate increase request.

Selection of Wisconsin TOD Pricing as a Case Study

The Wisconsin Public Service Commission (PSC) has generally been considered to be a forward-looking body; and its activities in the area of electric rate reform, particularly relating to the initiation of time-of-day pricing, were considered worthy of study. Because of its activist position, the Wisconsin PSC has been the subject of other studies and reports, but these have focused on the results of various policies rather than on the processes followed.

It was determined during the initial visit to Wisconsin that the shift in PSC policy to time-of-day rates resulted from intervention by environmental and consumer groups in a routine rate case by a fairly small utility company. The hearings resulting from this case gave the Commission reason to issue a general order to all electric companies regulated by them to conduct studies on the feasibility of time-of-day rates for their customers.

It was also determined that, since all major providers of electricity in the state would be affected, a generic environmental impact hearing should be conducted, rather than separate hearings for each utility upon rate increase request. This generic process took place over a two-year period and produced substantial testimony. Finally, the series of orders in separate cases from 1974-1978 indicated a process of decision making in a regulatory case setting well worthy of detailed study.

Organization of the Case Study

The case study has been organized to provide the reader with a clear picture of the chain of events in the rate redesign process in Wisconsin, while at the same time providing the necessary analysis of the relevant issues. Section E of this introductory chapter provides a detailed description of the parties involved, including the Public Service Commission, the various utility companies affected and the intervening environmental groups.

Chapter 2 provides the general background information needed to understand the rate reform activities and, thus, focuses on the pricing of electricity and the reasons for changing the traditional pricing structure.

General information on each of the major rate cases involved in instituting time-of-day pricing is provided in chapter 3. This includes a chronology of events as well as an overview of Commission activities and policy trends.

A detailed analysis of each case and its attendant issues is also presented in chapter 3. Because the orders in each case are so different, the cases have been considered separately.

The process was initiated as a result of environmental intervention and, therefore, environmental concerns are of major importance. Thus, the fourth chapter deals with these matters. In particular, the Wisconsin Environmental Protection Act is discussed, as is the court case which determined that the filing of an environmental impact statement was required because of the potential environmental impacts resulting from major changes in the manner of pricing electricity. The environmental impact statement itself is also discussed.

The final chapter provides an overall assessment of the rate design process as well as conclusions regarding the manner of making major policy changes through rate case hearings and the developments likely to result from the actions of the Wisconsin Public Service Commission.

Description of Participants

Public Service Commission

Several parties have been involved in the Wisconsin time-of-day electricity pricing experiments. Although the Wisconsin Public Service Commission is the main participant in this process, utilities have also been participants.

During the course of this activity the composition of the Wisconsin Public Service Commission changed considerably. The present Commission is comprised of Charles J. Cicchetti, Chairman, and John C. Oestreicher and Edward M. Parsons, Commissioners. Chairman Cicchetti, a former economics professor and energy counselor to the Governor, was appointed to fill a vacancy in the chairmanship in May 1977. He had previously appeared before the Commission as a witness for the Environmental Defense Fund in the first Madison Gas and Electric Company case. Commissioner Oestreicher, a former state legislator and city attorney, was appointed in January 1976 and Commissioner Parsons was appointed in late 1977.

Because of the changes in membership, most of the five major rate cases were decided by different panels of Commissioners. As indicated in Table 1, when the first Madison Gas order was issued, the Commission consisted of Chairman William F. Eich and Commissioners Richard D. Cudahy and Arthur L. Padrutt. Commissioner Padrutt dissented from the Madison Gas order, which required all electric utilities to begin studies on the feasibility of time-of-day pricing. The panel was also sitting when Wisconsin Power and Light made its application for a rate increase.

Table 1: Activities Of The Wisconsin Public Service Commission

YEAR	COMMISSIONERS	CASES INITIATED	ORDERS ISSUED	EFFECT
1974	Eich (Chairman) Cudahy Padrutt	Wisconsin Power and Light (2-U-7778)	Madison Gas and Electric I (2-U-7423)	Investigate feasibility of TOD pricing; Institute summer/winter differentials
1975	Cudahy (Chairman) Clapp Holden	Madison Gas and Electric II (3270-UR-1)	Wisconsin Public Service Corp. (interim) (6690-UR-1)	Flatten rate structure
1976	Clapp (Chairman) Oestreicher Holden	Wisconsin Electric Power Company I (6630-ER-1)	Madison Gas and Electric Co. II (3270-UR-1) Wisconsin Power and Light (2-U-8085)	Initial implementation of TOD rates for some commercial customers
1977	Clapp (Chairman) Oestreicher Holden	Wisconsin Electric Power Company II (consolidated with WEPCO I)	Wisconsin Public Service Corp. (final) (6690-ER-5)	Begin three-year experiment on residential TOD rates
1978	Cicchetti (Chairman) Oestreicher Parsons		Wisconsin Electric Power Company (6630-ER-2 and (6630-ER-5)	Institute TOD rates for all general and primary and largest

Source: Data derived from final order issued in each rate case.

Within a year, Eich had left the chairmanship, which was then assumed by Cudahy, and Padrutt had left the Commission. The vacancies left by Padrutt's departure and Cudahy's move to the chair were filled by Norman M. Clapp and Matthew Holden. This panel was sitting while hearings occurred on the Wisconsin Power and Light case and when Madison Gas made its second rate increase request. This panel was also responsible for the order in the Wisconsin Public Service Corporation case, which authorized a joint five-year study between the Commission and that utility (with funding by the Federal Department of Energy) to perform a controlled rate experiment. This order specifically required the installation of timed metering devices necessary to conduct the experiment.

In 1976, Mr. Clapp replaced Mr. Cudahy as Chairman of the Commission, creating a vacancy which was filled by John C. Oestreicher. Mr. Holden remained as a Commissioner. This panel gave the order in both the Wisconsin Power and Light and the second Madison Gas cases. It also authorized rate relief for revenue purposes for Wisconsin Electric Power and began hearings on time-of-day rate design for Wisconsin Electric Power Company. Hearings for the actual rate design and price levels to be applied in the Wisconsin Public Service Corporation study continued at this time.

By the spring of 1977, Chairman Clapp had left the Commission, and his position was filled by Dr. Cicchetti in May. Rate design and price levels were decided upon in January of that year for the Wisconsin Public Service Corporation study, and while hearings were continuing on the WEPCO case, the Commission received a second WEPCO increase request. The present Commission, composed of Oestreicher, Parsons and Cicchetti, was responsible for the WEPCO order in early 1978, Mr. Parsons having been appointed to the position vacated by Mr. Holden in late 1977.

The orders issued by this changing Commission, over a four-year period, indicate an increasing commitment to marginal cost pricing to be achieved through the establishment of TOD rates. With the exception of Oestreicher, no one individual has been on the Commission for more than two years of this process, or has been involved with any single case from the beginning to end.

Utilities

Although there are 11 main electric utilities serving the state of Wisconsin, only four of them have thus far been actively involved in decided major TOD rate design cases. These are Madison Gas and Electric Co., Wisconsin Power and Light Co., Wisconsin Public Service Corporation and Wisconsin Electric Power Co. (WEPCO), all of which are investor-owned utilities. These four utilities vary considerably in size and structure.

Madison Gas is the smallest, with approximately 88,000 retail electric customers (most of which are residential), and an annual net generation of 1,714,823,100 kWh. Only two of Madison Gas's customers, the University of Wisconsin and Oscar Mayer Company, are large consumers of electricity. Madison has a summer peak in July that is 75,000 kW higher than the winter peak in December.

Wisconsin Power and Light serves over 266,000 customers and has an annual net generation of 5,923,027,156 kWh. Like Madison Gas, Wisconsin Power and Light has a summer peak in July, and this peak is 30,000 kW higher than the winter peak in December.

Wisconsin Public Service Corporation is of comparable size, with an annual net generation of 5,976,613,700 kWh and over 249,000 customers. It also has a summer peak in July, but this peak is 40,000 kW lower than the December winter peak.

Wisconsin Electric Power Company is considerably larger, with 658,045 customers, and an annual net generation of 12,839,040,000. Its summer peak occurs in August, rather than in July, and is almost 400,000 kW higher than in the winter peak in December.

These four utilities account for almost 80 percent of all power generated in the state of Wisconsin. Thus, the actions of the Public Service

Commission have a great potential for substantial impact on electric consumption in that state. If the Commission's policies are applied to all companies requesting rate changes, the impact will become even greater.

Other Organizations

There are two environmental organizations which have been very active in the state's electric rate redesign efforts. Wisconsin's Environmental Decade and Friends of the Earth both entered rate cases as intervenors and have stated public positions on energy policy.

Wisconsin's Environmental Decade (WED) is a citizens' group of about seven hundred members and employs two full-time staffers, one of whom is an attorney. It became active in this area in 1972 by supporting the establishment of a pricing context that would lead to reduced consumption of electricity. As it has argued in these cases, WED finds peak load pricing to be inimical to environmental goals as it will promote new growth. It argues that by emphasizing lower rates in the off-peak hours the rate schedules proposed will increase consumption at those times. This is especially true, it believes, in the case of WEPCO, whose off-peak rate for electric usage is lower than rates for oil or gas. WED feels that the rates proposed would not have an appreciable effect on the system peaks as they presently exist; moreover, by filling in the "valleys," these rates will lead to increased consumption. The implication of this, in WED's opinion, is an increased reliance on nuclear power (strongly opposed by WED), which presently accounts for about 35 percent of Wisconsin's electricity.

Friends of the Earth (FOE) is a national conservation organization which has focused on energy-related issues. It began as an offshoot of the Sierra Club in 1969. Nationwide, it has about 20,000 members, and in Wisconsin there are about 500. Like WED, FOE supports energy conservation and opposes the use of nuclear power. The Wisconsin branch of FOE has followed the national group's orientation and shares its energy philosophy.

It has actively followed the actions of the Wisconsin Public Service Commission in the area of rate redesign, and views with some skepticism the expected results of time-of-day pricing. FOE feels that time-of-day pricing is being sold to customers as an inducement to consume more electricity in off-peak hours. It argues that structure of the rates approved is such that the off-peak periods are well defined, but the peaks are not; so no real shifting of consumption will occur. FOE feels that time-of-day pricing should be adaptable to use of soft-technology means (solar, wind power) for electricity generation. It fears that time-of-day rates may be used to justify large facilities using nuclear fuel, coal or oil for generation. FOE favors the concept of time-of-day pricing as a form of marginal cost pricing, but not as that concept is being applied in Wisconsin.

Other groups which have been involved, though to a lesser extent, are the Capital Community Citizens and the Environmental Defense Fund. Their roles have for the most part been limited to the first and second Madison Gas cases. Their position, however, has differed from that of WED. They favor TOD pricing because of its economic justification, even though it may not lead to decreased usage. It would appear that this position, in combination with testimony of economists in Madison Gas I, has been a prime factor in the development of TOD rates.[1]

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[1] Interview with Richard D. Cudahy, May 11, 1978, Washington, D.C.

CHAPTER 2

STATE ELECTRIC UTILITY RATE REFORM IN THE UNITED STATES

Survey

In order to place the Wisconsin experience in perspective, it is necessary to discuss in a general fashion the development of electric utility rate reform in the United States.

Electric utility rate reform has received much attention within the various state utility commission jurisdictions through the country. The rapid increases in utility rates, along with increased consumer interests in environmental issues and in energy conservation, have caused many state legislatures and utility commissions to take up the issue of utility rate structure reform.

Two recent surveys of state utility commission involvement in electric utility rate reform have reported a wide range of activity at the state level in the many issues involved in redesigning electric utility tariffs. Although average cost based, declining-block rates are still the predominant form of electric utility tariff; the increased and increasing involvement of state commissions in utility rate reform indicates that the traditional methods of designing electric utility tariffs may soon be a thing of the past.

National Economic Research Associates (NERA) conducted a survey of state utility commission involvement in electric utility rate reform. The results of this survey were presented to the Eighty-Ninth Annual Convention of the National Association of Regulatory Utility Commissioners in New Orleans, on November 16, 1977.[1] Additionally, Electricity Consumers

[1] "Rate Structure Revision: A Federal or State Problem?", by Irwin M. Stelzer, President, National Economic Research Associates, Inc. Before the Eighty-Ninth Annual Convention, National Association of Regulatory Utility Commissioners, New Orleans, Louisiana, November 16, 1977.

Resource Council (ELCON) conducted a survey of state utility commission activity in the area of electric utility rate reform covering the period of January-February 1978.[1] Although not as detailed a survey as that performed by NERA, the information presented by ELCON serves as an update of the data provided in the NERA survey. The information provided by the two surveys leads to the following observations:[2]

(1) Commissions in 28 states have a policy, either stated or informal, of discouraging declining block rates.

(2) Commissions in 41 states have approved and currently have in effect seasonally varying rates.

(3) Generic rate proceedings investigating general rate structure design concepts have been held in 24 jurisdictions: Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, New Hampshire, New Mexico, New York, North Carolina, Oregon, Pennsylvania, Rhode Island, South Carolina, Texas, Utah, Washington and Wisconsin.

(4) Commissions in 26 states have approved time-of-day rates, on an experimental or permanent basis, for at least one class of customers of an investor-owned electric utility. These states are Arkansas, California, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Pennsylvania, Rhode Island, South Dakota, Vermont, Virginia, West Virginia and Wisconsin.

(5) Utilities in 14 states measure marginal or incremental costs for each customer class. These states are Alabama, Arizona, Arkansas, California, Colorado, Hawaii, Illinois, Indiana, Kentucky, New York, North Carolina, Oregon, Virginia and Wisconsin.

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[1] State Electricity Update: January-February 1978, by Electricity Consumers Resource Council, Washington, D.C.

[2] The data provided include responses from 49 states and the District of Columbia. The one state not included, Nebraska, contains no privately owned electric utility companies and relies on local regulation of the publicly owned utilities within that state.

(6) In five states, the commissions require utilities to measure the marginal or incremental costs of service by customer class. These states are Alabama, California, New York, Oregon and Wisconsin.

The data collected in the two surveys, parts of which are summarized above, point out that electric utility rate reform is an issue which is currently undergoing extensive analysis within many jurisdictions throughout the country. The Wisconsin Commission is one of the foremost advocates of implementation of electric utility rate reform. Wisconsin is one of only five states whose commissions require utilities to measure the incremental cost of providing service for each customer class. It is also one of four states (the others being Connecticut, New York and Virginia) which require utility companies to measure the differences in the cost of providing service to each customer class at various times of day in addition to various seasons of the year. Of the states which currently have approved time-of-day rates, 13 are on an experimental basis and six are on an optional basis. Only eight states, including Wisconsin, have authorized mandatory time-of-day rate structures. Although marginal cost-based time-of-day pricing has not yet been adopted on a wide-scale basis, increased state utility commission involvement in electric utility rate reform, similar to the Wisconsin experience, seems likely.

Rate Systems and Proposals

General

In the past, most regulatory agencies have dealt almost exclusively with the question of utility revenues and earnings, leaving the question of rate structure to the companies. The regulators' preoccupation with avoiding monopoly profits was understandable in view of the steadily declining costs experienced by the industry coupled to a general perception of limitless, inexpensive energy.

With the recent turnaround in this situation where costs have begun to rise and the considerable emphasis has been placed on conservation, the concern of commissions has moved to the determination of who was going to pay the bill, and how this might best be accomplished.

In most U.S. jurisdictions, utility rates are generally based on fully allocated cost, adjusted for the value of service. Fully allocated costing is a method of distributing the revenue requirement established for the company among customer classes and usage blocks through a variety of complex systems. To accomplish this distribution, costs are first broken down by function (production, transmission, distribution, etc.) and by classification (demand, energy, customer, etc.). The largest single item consists of the demand charges. In some cases the demand allocation is computed based on the customer class contribution to the system peak; in other cases it is based on the noncoincident peak; and in still other instances, the diversity in usage patterns between customer classes is given weight. There are approximately 30 variations of these three basic allocation systems in use.

Once the cost-of-service study has been prepared, rates are promulgated based on the allocations in the study, but adjusted to reflect the competitive situation, institutional and political factors and societal goals, The adjustment process is generally known as "value of service" pricing.

The rate structure resulting from the above computations and adjustments has generally been a dual structure--one rate for residential and one for other customers, as indicated in Tables 2 and 3. The residential rate is typically a one-part rate usually arranged to decline with greater use. The latter characteristic results from the inclusion of customer and fixed costs into the first few blocks of the schedule. In some instances, a modest fixed charge might be collected.

Marginal Cost-Based Rates

These traditional concepts discussed above are currently under attack by those favoring use of marginal cost or time-of-day pricing. Marginal cost is the cost of producing one more unit of something and thus reflects the resources needed to supply more or less of a product. As such it is a measure of the alternatives that have to be given up.

Table 2: Example Of Typical Residential Rate Structure

Fixed Monthly Charge - $1.00;
Energy Charge,

first	100	kWh used per month	- 3.80 ¢/kWh
next	400	kWh used per month	- 2.55 ¢/kWh
next	500	kWh used per month	- 2.25 ¢/kWh
next	1,000	kWh used per month	- 2.20 ¢/kWh

Commercial and industrial customers, on the other hand, generally pay a two-part rate--a demand conponent to cover the cost of capacity and an energy component to cover variable costs. Both parts of the schedule are usually arranged in declining steps. As a consequence, low-load factor customers pay a higher price for electricity than that paid by high-load factor users. This is based on the assumption that high-load factor customers will tend to reduce costs for all customers and thus should be encouraged.

Table 3: Example Of Typical Commercial and Industrial Rate Structure

Demand charge (per month)

$2.80 per kW for the first 50 kW
$2.40 per kW for the next 150 kW
$2.10 per kW for all over 200 kW

Energy charge (per month)

2.05 ¢/kWh for the first 10,000 kWh
1.64 ¢/kWh for the next 10,000 kWh
1.30 ¢/kWh for the next 180,000 kWh
1.20 ¢/kWh for all over 200,000 kWh

The energy charges under both of these rates are also usually subject to a fuel adjustment clause.

Marginal cost thus provides the correct price signal in terms of economic efficiency by permitting the consumer to judge whether the satisfaction derived from the purchase of a product is worth the sacrifice of other goods and services. Marginal cost pricing of electricity is designed to charge the economically correct price. It is not intended by itself as a device to level load, enforce conservation or achieve a social goal. Marginal cost is the economically proper price, but there has been difficulty in its application. One of these difficulties has come to be known as the problem of second best. That is, if those sectors of the economy competing with electricity do not also utilize marginal cost pricing, an optimal allocation of resources may not be achieved. During a time of increasing costs, consumers would shift to the average cost industries, because their prices would rise at a slower pace. When costs are declining, the reverse would be true. These problems could, to some extent, be corrected or alleviated through proper rate design. In addition the Wisconsin Commission staff argue that these problems could also be corrected through, (a) The choice of cost minimization in the electric utilities industry as the objective, rather than welfare maximization, and, (b) pricing energy in other industries at or near marginal cost.

In addition to the above, there is the revenue problem. That is, when marginal costs are higher than embedded average costs, a utility using marginal cost pricing might receive too much revenue to meet the regulatory constraint of a fair and just rate of return; when marginal costs are lower than embedded average costs, the reverse might occur. The Commission staff feel that this problem may be overcome by pricing only marginal use at marginal cost -- the necessary and sufficient condition for economic efficiency. They note that methods of implementation for the increasing marginal cost situation includes, (a) prorated customer cost and, when necessary, demand charges; (b) inverted rates; (c) benchmark pricing which prices historic use at a lower than marginal rate. The inverse would be used in a situation of declining marginal cost.

Aside from these problems, there have been differences over how to measure and compute marginal costs. These can be considered as costs incurred in the short run or in the long run, as the cost for the last kWh or for an increment of kWh. Several implementation concepts have been proposed. The earliest was long-run incremental cost. This requires the development of costs for relatively large increments of future capacity, and involves consideration of investment decisions, demand forecasts, and so forth.

It has also been suggested that long-run marginal costs can be developed by changing the unit capacity and energy costs of peaking equipment for all consumption at the system peak, marginal energy costs plus a proportionate share of capacity costs on the shoulder, and marginal energy costs only during the off-peak period. The Commission staff feel that while this may be fine for an optimal or least cost system, an adjustment must be made if base load plant is brought forward for the sake of fuel economies. The Commission staff feel that the capacity costs of a nuclear plant so constructed at $1,000 a kilowatt may be $200, with $800 going into fuel savings. These savings, they argue, are protected by the remaining less efficient plant sitting above in the dispatch order.

A more recent methodological innovation has been the determination of pricing periods based on the probability of being unable to meet the load. These periods having the greatest probability are designated as the peak period, those with the least are off-peak and all else is the shoulder. In some instances, the loss of load probabilities is used to allocate the costs to time periods. In other cases, the full cost of the peaking unit is assigned to the designated peak, with marginal running costs being used for the other two time periods.

The Commission staff believe that these differences in computation have generally produced far less of a difference in marginal costs than the 29 or so allocation methods used to compute average embedded cost.

The Commission staff believe that during the May 1-4, 1978 State of the Art Conference On Marginal Costing, held in Montreal, marginalists appeared to have minimized all computation decisions.

Time-of-Day Pricing

The rationale for time-of-day (TOD) pricing is similar to that for marginal costing. In fact, it is probable that marginal costing will require TOD pricing, although TOD does not require estimates of marginal cost.

In any case, TOD pricing is based on the fact that electrical supply-demand conditions will vary by time of day. As a consequence, the configuration of equipment used, and hence the costs, will also vary by time of day. If rates are to track costs, then they must vary accordingly.

The implementation of TOD pricing poses a problem somewhat similar to that of marginal cost pricing in terms of revenue stability. That is, because rates would be higher at the peak, as would usage, the utility would derive a major portion of its revenues from peak usage. As a consequence, for systems having a large air-conditioning load, a cool summer with relatively cool days would result in inadequate revenue. A hot summer would mean excessive gross revenue. TOD pricing will mean greater gross revenue sensitivity to the weather.

On the other hand, the present Commission staff of the WPSC feel that marginal profit stability for the utility is enhanced. The utility is less likely to overbuild or underbuild when the correct price signal is given.

There are also questions about the costs versus the benefits of instituting time-of-day pricing. Some feel that the cost to residential customers ($200) needed for this pricing systems may outweigh the benefits of reduced generating capacity. Others, including the present staff of the WPSC, believe that metering costs are now down to $95 installed and may be halved again in a few years. Large customers with digital demand recorders will not need new metering for TOD rates. In the event TOD pricing for small users proves not to be cost effective, seasonal rates based upon marginal cost may be helpful.

Those who favor reduced energy use rather than cost minimization as the major goal of rate reform do not believe TOD pricing will accomplish the purpose. It can be argued that there is a possibility that the peak would be reduced, but that total energy consumption would not decline. Others would maintain that load factor would improve, and the consequent use of more efficient generating units would have a beneficial impact on consumer rates.

Lifeline Rates

Under the lifeline concept, a subsistence quantity of electricity is priced so that it is within economic reach of all. Generally, the first several hundred kWh consumed monthly by each residential customer are priced at a rate no higher than the lowest energy rate charged any other class. As a result, the subsistence electric price tends to be below the cost of providing residential service and, as such, is a subsidy. Those in favor of lifeline rates generally regard income distribution as a major priority of rate setting and desire to include social costs in establishing electric utility rates. There is a good deal of controversy over whether this kind of subsidy should be undertaken through rates or the welfare system. There is also a division of opinion as to whether lifeline rates will help those in need or just those who use relatively little electricity. Moreover, questions have been raised as to how poor persons living in master-metered apartments might benefit, and how to balance the equities between those who heat electrically and those who use other fuels.

Despite the theoretical advocacy of the economist, it is only recently that either marginal cost or TOD pricing has been implemented in the United States. Several other countries in Europe have used these rate and costing forms for at least 10 years. A leading state in the implementation is Wisconsin. The next chapter will describe the details of the adoption of TOD pricing in Wisconsin.

CHAPTER 3
TIME-OF-DAY PRICING IN WISCONSIN

Introduction

The development of TOD pricing in Wisconsin has proceeded steadily, with each case bringing new advances. Moreover, the development has been orderly: the Wisconsin Commission has recognized when there is a need for data and when there is a need for action. Gradually, the message has been sent to the Wisconsin electric companies that marginal cost pricing is going to be utilized, and the utilities also, have come to accept the present reality of the situation.

What has resulted--although not completely planned--is a situation in which each utility, subject in turn to marginal cost pricing, has received a somewhat different strategy of implementation. Thus, each company has a different set of rules in application, and the Public Service Commission expects that such a situation will yield positive experience for others.

Thus, in the 1974 Madison Gas and Electric rate case (MG&E I)[1]--an early landmark in TOD pricing--the Commission, while exploring a number of areas, limited the principal impact of its order to winter/summer pricing differentials. It ordered Madison Gas and Electric to investigate the feasibility of time-of-day pricing but did not order immediate use of such pricing because of unknown factors related to equipment costs. The Commission also indicated that in the future declining-block rates or other kinds of rates were not likely to be approved unless justified by a showing of unusual circumstances.

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[1]Docket numbers for major decided cases are referenced on page 6 and in Appendix J.

In Madison Gas and Electric II, the Commission ordered time-of-day rates to be applied to MG&E's two largest customers, Oscar Mayer and the University of Wisconsin. Additionally, the Company was ordered to begin consideration of time-of-day rates for other large customers, a process now under way.

The next case--that of Wisconsin Power and Light (WP&L)--represented a substantial implementation of TOD pricing in Wisconsin. Time-of-day rates were ordered for all commercial and industrial customers where maximum monthly measured demand exceeds 500 kW for eight out of 12 months. In addition, time-of-day rates were made optional for all customers using at least 200 kW. The peak period was defined as 8:30 a.m. to 10:00 p.m., Monday through Saturday, excluding holidays.

The fourth case, Wisconsin Public Service Corporation (WPSC), began with a voluntary time-of-day pricing proposal submitted by WPSC and funded by the Federal Energy Administration. In this experiment time-of-day meters were installed in a stratified random sample of 700 residential customers. This experiment was made mandatory by the Commission and is now in progress.

The most recently decided case, Wisconsin Electric Power, extends the TOD pricing policy even further. TOD rates were required as of July 1, 1978, for the 577 largest residential customers and for all general primary customers. On-peak times were established to fit the usage patterns of each class. Decentralized computers will be used to permit two-way remote metering for residential and small-volume commercial customers.

Finally, there are other current pending cases. The most prominent of them is the Northern States Power Company case, in which the Commission has ordered the Company to do significant research on load factors and other information related to TOD pricing.

It would appear that a number of factors were responsible for the Wisconsin Commission's progress. As Charles J. Cicchetti, the current Chairman of the Commission, has remarked, Wisconsin has had a history of "continual enlightenment and progressive tradition."[1] This factor, which can be overstressed, should not be minimized in importance: "It should not be a surprise then, to find it among the handful of states breaking into the time of use implementation ranks."[2]

Especially important was the personal interest of Commission Chairmen, Cudahy and Cicchetti. According to one current staff member, "Cudahy was the largest moving force in the Madison Gas case." This was confirmed by another staff member who added, "Cudahy just had the idea and pushed it." Indeed, although the Commission has had a large turnover in the past several years, only Commissioner Padrutt, who has since left, opposed the general notion of time-of-day rates. Cudahy's strong support was advanced by the current Chairman, Charles J. Cicchetti, who in the past has spent considerable time testifying throughout the country about time-of-day pricing. Under his chairmanship, time-of-day orders have become increasingly broad based and comprehensive. Cicchetti also enjoyed the support of Governor Patrick Lucey, who was strongly in favor of marginal cost pricing. Indeed, Cicchetti is "convinced that (his) appointment was in large part based upon...commitment to marginal cost principles."[3]

In the sections to follow, we will describe in turn each of the cases outlined above. Each is perhaps best treated as a separate "experiment," for each case differs from the others. Following this, there will be an overall evaluation of all the cases, as well as a discussion of the factors producing the Commission's decisions and the likelihood for transferability to other jurisdictions.

It is important to emphasize that while the Commission's members and staff were substantially motivated by theoretical concepts of marginal cost pricing, their orders were, for various reasons detailed below, expressed in

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[1]Charles J. Cicchetti, Marginal Cost Pricing: The Transition from Theory to Tariffs, p. 1.

[2]Ibid. at 15.

[3]Ibid. at 1.

terms of TOD pricing. Thus, the story in Wisconsin is really a TOD story. Marginal cost pricing principles provided the impetus for reform but were modified to account for pragmatic considerations.

The Beginning: Madison Gas I
(Docket No. 2-U-7423)[1]

The Madison Gas case began in early 1972, when MG&E filed an application to seek a rate increase. After a series of hearings on interim and permanent rates, additional hearings were held in late 1973 and 1974 on the subject of electric rate design.

The hearings in the case covered 18 full days of testimony over a period of nearly two years, and the transcript of the hearings (exclusive of exhibits) consisted of approximately 3,000 pages. As a concurring Commissioner stated: "What began as a rather routine proceeding involving a medium sized utility became...a 'national' test case on electric rate redesign."[2] The change in emphasis from an ordinary rate case came about as the result of the intervention of two groups--the Capital Community Citizens and the Environmental Defense Fund. All three Commissioners wrote separate opinions (one of which was a dissent), and the list of witnesses, which included appearances by the representatives of most of the Wisconsin power companies, consumer and environmental groups, banks and commission staff, covered 10 full pages alone. In making its decision on the issues, the Commission applied the decided principles not only to Madison Gas, but to "other electric utilities under this Commission's jurisdiction facing similar operating conditions."[3]

The Commission started with the acceptance of certain principles advocated by most of the witnesses: all agreed first that rates should promote an efficient allocation of resources to discourage wasteful use

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[1] See Appendix J for a list of the docket numbers of major decided cases.

[2] William Eich, concurring in 2-U-7423, p. 18.

[3] Opinion, 2-U-7423, p. 18.

of energy. Second, rates should not be discriminatory. Third, rates should lead to stable revenues. Fourth, rates should reflect a sense of historical continuity. In addition to acceptance of the basic principles, there was "reasonably general agreement among all parties"[1] that the idea of an efficient allocation of resources implies that rates should properly reflect the marginal cost of providing service to customers.

In general, the remainder of the opinion in the first Madison Gas case concentrated largely on the idea of efficiency and generally excluded detailed discussion of gross revenue instability, historical continuity[2] and, especially, societal effects of marginal cost pricing. This is not to suggest that such questions were not considered at all, but they clearly were in the background. Indeed, the use of marginal cost pricing as a means of simply reducing energy usage (an important concern of some of the intervening environmental groups) often seemed overshadowed by the objective of economic efficiency. Although, for example, the Commission "liberally admitted environmental evidence in this proceeding and considered environmental factors,"[3] there is very little discussion of environmental (not to mention social) issues in the opinion itself. The dissenting Commissioner was prompted to suggest that "...for some 3,000 pages of testimony and reams of exhibits and studies, the economic experts who appeared as witnesses leaped and gamboled, like mountain goats, from peak to crag to precipice in the rarified upper atmosphere of theoretical economics" while those less learned in economics "were left to slog painfully through the foothills below."[4]

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[1] Ibid. p. 3.

[2] As noted later, however, historical continuity has been of special importance to the Commission.

[3] Richard Cudahy, concurring opinion, p. 46 (2-U-7423).

[4] Arthur Padrutt, dissenting opinion, p. 47 (2-U-7423).

An initial issue was the concept of marginal cost to be applied. The Commission noted that:

> The "Marginal Cost" of an item refers to the change in cost that occurs with infinitely small changes in output. A central proposition of economic theory is that when prices of goods and services are set equal to their marginal costs of productivity an optimum allocation of resources results.[1]

Recognizing that measurement of marginal cost is difficult and can be attempted for the short run or the long run, the Commission chose to emphasize long-run incremental cost--the "incremental cost of the capacity and output which can reasonably be expected to be added in the next several years."[2] Using long-run incremental costs (LRIC), the Commission reasoned, is more practical (since they felt short-run marginal cost is more difficult to measure) and much less volatile.

While recognizing that full peak load pricing would be required to deal adequately with LRIC, the Commission limited its order to a winter/summer price differential proposed by the applicant to deal with the problem of summer peaking.

The Commission refused to go beyond this to full TOD pricing, since meter costs were unknown, and no evidence thereon had been presented. The applicant, together with other large utility companies, was ordered to study the problem of obtaining cost figures in TOD pricing.

The Commission also revised rates among certain classes to reflect more accurately the cost of provision of power to these users. Thus, industrial rates were increased and commercial rates decreased. In addition, the Commission ordered a summer/winter differential for residential use and the replacement of declining-block residential rates

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[1] Opinion, 2-U-7423, p. 4.
[2] Ibid. at pp. 4-5.

by flat rates. Finally, where rate schedule distinguished between energy and demand charges, the Commission ordered a general shift in revenues from energy to demand charges.

The declining-block pattern of existing rate concepts was challenged in this case on the grounds that costs were no longer declining, and current rate structure encouraged uneconomic use by giving the consumer an incorrect price signal. This, it was argued, led to a costly expansion of capacity and a further misallocation of economic resources. To avoid such a situation rates should be altered to reflect marginal cost.

In the course of the case all parties agreed that rates should promote the efficient allocation of resources, and the Commission claimed that this could best be accomplished through marginal cost pricing. An important issue in the case then became how to define and implement marginal cost, given that rates were not to be discriminatory, were to result in stable revenues for the utility and had to reflect a sense of historical continuity.

In theory, the economically efficient price is the short-run marginal cost of the smallest possible additional unit of sale. This concept, however, the Commission reasoned, is hard to measure and administratively difficult to apply. It can also lead to extremely volatile rates and revenues. This occurs because short-run marginal costs change as the level of output changes and as operating characteristics vary. As a consequence, there was a general acceptance by the Commission of long-run incremental cost as a proxy for marginal cost. LRIC is not derived from small and continuous additions to output but from the incremental cost of capacity and output expected to be added over the next several years.

LRIC is divided into three components: (1) those, such as meter reading and billing, that vary with the number of customers (customer cost); (2) those future costs equaling capacity commitments that vary with kW demand (demand cost); and (3) operating and maintenance costs that vary with the kWh consumed (energy costs). The cost allocation engendered some controversy with some parties feeling there was an excessive amount of the cost of distribution included in customer cost. Inasmuch as only one LRIC study was presented, there was no opportunity to evaluate a different cost apportionment method.

The Commission felt the appropriate benchmark for the design of electric rates was marginal cost, and that LRIC the logical starting point. In doing so, it noted that LRIC does not mean that their rates will be valid over a long time into the future, or that they will compensate for inflationary cost increases.

This latter point was also one of contention, with some parties feeling LRIC should take account of inflation, and others feeling costs should be expressed in constant dollars. It was eventually agreed that the cost of additions in constant dollars over the next 10 years should be included in LRIC. The Commission held this definition to be consistent with economic theory but provided for an attrition allowance to guard against future inflation.

Another major issue concerned the desire of some parties to include external costs in rates. Others felt external costs should be covered by a tax. Still others suggested that they should be included insofar as quantifiable but noted that if external costs were not also included in the price of substitutes the pricing signals would be distorted. Another position suggested that these costs should be reduced rather than being reflected in rates due to the difficulty of accurately computing external costs. The Commission ruled that external costs involve broad questions of policy that cross multiple industrial and energy lines, and therefore should be levied through taxation, not rates. To collect external costs from utility customers and not others would discriminate against utility customers.

A final item considered in Madison Gas I was the question of peak-load pricing. Under this system, rates vary with the time-of-day in order to reflect the variations in cost that occur with load variations. Thus, consumers pay the actual cost their use of electricity imposes on society and are given incentives for shifting their use to the off-peak period. It was generally agreed that peak-load pricing was an application of LRIC. This could be approximated to a limited extent through a winter/summer differential. Under the latter, the space-heating customer uses excess capacity in the winter and is not charged for the cost of capacity added to serve the summer peak.

This implementation at TOD rates for all customer classes requires the installation of recording meters. In the course of the case, however, no data regarding metering costs and benefits were introduced. It was noted that commercial-industrial customers generally have the proper type of meters already installed. As a consequence, benefits and costs for these customers, the Commission noted, should be carefully examined. If TOD can be applied to the commercial-industrial customer, it could result in lower costs for large users and improved system load factor.

To implement the move toward LRIC, the Commission ordered revisions in rate structure as well as additional studies. First, the Commission flattened energy rates.

In addition, customer-related costs were affected. At that time these costs were collected, in part, through a fixed charge, with the remainder spread through the early rate blocks. This system offset possible overestimation of customer costs and eliminated customer objections to charges not dependent on consumption. On the other hand, the record indicated that customers costs should be collected entirely as a fixed charge. To do otherwise, it was argued, would magnify the differential between the early blocks and the tail block. On this basis, the Commission established a fixed customer charge for residential customers but did not set it at the theoretically proper level. The necessary increase was felt to be too big a change to make at one time. The fixed charge was set at $1.50 per month with the remainder of the customer costs loaded onto the first block. As a consequence, the first block carried a charge of 2.5¢ per kWh, but all succeeding blocks were 2.2¢. Winter use over 1,000 kWh was established at 1.5¢ per kWh.

The commercial rates resulted in a shift of revenue from energy charges to demand charges and also established a summer/winter demand charge. Winter demand would start at $2.00 for the first 10 kW, then range between $2.30 to $1.50 per kW depending on the demand block. The summer rate started at the same point but ranges between $2.60 and $2.00 per kW. The energy charge ranged from 2.6¢ per kWh for the first 500 kWh to 1.25¢ for use over 50,000 kWh in both summer and winter. Industrial rates were restructured in a similar fashion.[1]

As a result of these efforts to adjust rates to conform with the LRIC study, the charges rose or declined as indicated below:

(1) AC power -1.57%
(2) Capital Heating +5.2%
(3) Municipal Water Pumping +0.2%
(4) University of Wisconsin +0.5%
(5) Residential -0.01%
(6) Oscar Mayer -0.08%
(7) Commercial Light and Power -0.9%
(8) AC Power Optional -1.5%

The increases and decreases were estimated to result in shifts in the class contribution to the revenue requirement as shown in Table 4.

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[1] For rate schedule comparison, see Appendix C.

Table 4: Changes In Revenue Requirement, By Class, Madison Gas & Electric I

Class	Percent of Revenue Raised: Old Rates	New Rates
Residential	36.9%	36.9%
Commercial	35.6%	34.1%
Power	15.0%	16.6%
University of Wisconsin	8.2%	8.3%
Oscar Mayer	1.0%	1.0%
Municipal Water Pumping	0.9%	0.9%
Capital Heating Plant	0.3%	0.2%
Other	2.1%	2.0%
TOTAL REVENUE	$30,132,233	$32,275,070[1]

Source: Order, Madison Gas and Electric I.

The Madison case gave greater emphasis to system cost characteristics than to load cost characteristics, because data on the latter were not available. The case decision did not lay down hard and fast rules but rather ordered a change in direction from an era where declining costs pointed toward declining-block rates to an era of cost uncertainty.

However, in structuring the case, virtually no testimony was introduced by traditional rate people. As a consequence, the unanimity on the desirability of marginal cost may be more an expression of the types of witnesses that appeared at the proceedings. On the other hand, supply and demand and appropriate prices are the domain of the economist. From this view the extensive testimony of members of that profession in this case has considerable logic and may indeed be a part of the importance of the case.[2]

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[1] For actual dollar values, see Appendix B.

[2] This is not to suggest that all public utility economists came down on the side of marginal cost as the principle criterion in ratemaking.

The Policy Statement

After the first Madison Gas case, the Commission issued a Policy Statement and notice of proposed Rule (Docket No. 01-ER-1).[1] Because of the political difficulty in Wisconsin of making rules outside of an individual case, the Commission never formally adopted the rule. Nevertheless, the document is instructive in understanding the development of the Commission's thinking concerning TOD and marginal cost pricing.

The Commission noted that TOD had worked well with commercial and industrial customers in England and France and was likely to work well in the United States with the same class of customers. It was somewhat more hesitant, however, to apply TOD rates to residential customers because of a lack of elasticity information and knowledge of all cost factors. Nonetheless, it thought it was time to begin to consider requiring TOD rates for residential and small commercial customers.

The proposed rule would have held as "presumptively deficient" any proposal for changed tariffs which failed to include a TOD proposal for customers having potential metering capability for TOD pricing (industrial and large commercial). The rule would have also required proposals for other customers to include some form of mandatory or voluntary TOD pricing, to provide for study of TOD rates together with subsequent proposed actions, or to provide for any reasonable alternative plan acceptable to the Commission.

Thus, although the proposed rule was never adopted, the Policy Statement laid the foundation for progressive, far-reaching action on the part of the Commission. From this point, the decisions were to become increasingly complex and applicable to additional classes of customers. In addition, as the staff gained greater sophistication in dealing with marginal cost pricing, the Commission was able to analyze the issues with greater understanding and expertise. This proposed rule, together with the broadly applicable nature of Madison Gas I, left no doubt as to the intent and commitment of the Commission to move toward uniform TOD pricing for all electric utilities in Wisconsin.

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[1] See Appendix A.

Applying Time-of-Day Pricing: Madison Gas II
(Docket No. 3270-UR-1)

By the time of the decision in Madison Gas and Electric II (November 9, 1976), Commissioner Padrutt had left the Commission and a unanimous Commission made a first, cautious step into time-of-day pricing. Although summer/winter differential and the energy/demand charge mixtures were changed again, the significant feature of the case was the introduction of TOD pricing to MG&E's two largest customers, the Oscar Mayer Company and the University of Wisconsin. In addition, the Commission ordered for all users inclusion of a customer service cost composed of the billing expenses, costs of the meter and service line and that portion of the distribution plant which varies with the number of customers.

The Commission also considered the implementation of a lifeline rate but rejected it because it had not been proved cost justified, its efficiency was questionable and the Commission could perceive no conservation effects. The Commission did, however, order an electric energy conservation rate for the residential customer who used less than 300 kWh per month (as well as similar plan for gas usage), to be submitted by the applicant.

The applicant noted during the case that it was voluntarily installing magnetic tape meters for customers with monthly demands over 500 kW. The Commission ordered a hearing for April 1, 1977, to consider TOD rates for the other large MG&E customers, but as of this writing, new rates have not yet been approved.

The peak period adopted for both Oscar Mayer and the University of Wisconsin was 10:00 a.m. to 9:00 p.m., Monday through Friday, excluding holidays.

This case reaffirmed the principles of the earlier Madison Gas & Electric case but moved forward another notch. Rates were cost based, their structure was flattened, the number of rate blocks was reduced and some additional rates were varied on a seasonal and daily basis.

Three cost-of-service studies were entered into the record in this case: one based on LRIC; one more closely aligned to the theoretical concept of marginal cost (MC); and a third constituting a fully allocated cost (FAC) study using the coincident peak demand method. The second study assigns capacity cost to time periods based on the probability of an outage (loss of load probability) and customer costs based on the concept of minimum-sized distribution facilities. These studies resulted in residential cost allocations as shown in Table 5.

Table 5: Comparison Of Residential Cost Allocation Studies For Madison Gas II

	LRIC	MC	FAC
Monthly Customer Cost/Customer	$ 4.33	$ 4.33	$ 2.42
Annual Demand Cost/kW	$ 95.00	$81.30	$ 113.00
Energy Cost/kWh	$ 0.0066	$ 0.01416	$ 0.007

Source: Order, Madison Gas and Electric II.

These studies also indicated the residential class was not contributing adequately to supporting the cost of the service. The Commission, however, felt it would be unreasonable to make an abrupt change. Therefore, the rate changes represented a step toward the needed readjustment. Working from the cost of service studies, the Commission set a monthly fixed charge of $2.00 per month per residential customer, a flattened summer energy rate and a greater increase in the higher blocks than in the lower for winter.

The commercial-industrial seasonal demand charges were increased and flattened while energy charges were modified to reflect the increased demand charges. A special AC (alternating current) power rate was closed to new customers. The reason for a separate AC rate for customers no longer existed, since all commercial-industrial customers are now served from the same lines. Current customers were left on the old rate in order to minimize the impact on these customers. TOD rates were instituted for Oscar Mayer and the University of Wisconsin, but the Municipal Water

Pumping and the Capital Heating Plants continued on more traditional rates. Data on the latter two customers were not adequate to permit institution of such rates.[1]

Aside from the above, a major rate issue considered was the question of lifeline rates. It was argued these are socially justified, easy to understand and have an energy conservation appeal. Such rates, however, may not be justified on economic or cost-of-service principles. Rather, they constitute a subsidy to users below some established limit. The ostensible purpose of lifeline rates is to provide aid to the poor and elderly; but testimony in this case indicated that lifeline rates do not meaningfully provide aid, because they make no differentiation between customers using space and water heating and those who use other fuels. Lifeline rates can also provide an incorrect price signal by resulting in reduced utility bills in some cases. The Commission felt it was an income distribution question beyond its legal and technical authority. It felt this kind of question should be handled by other agencies of the government. The Commission, therefore, ordered the Company to develop a conservation rate only for residential customers with monthly consumption below 300 kWh.

The Next Step Forward: Wisconsin Power and Light
(Docket Nos. 2-U-7778 and 2-U-8085)

The crucial aspect of the Wisconsin Power and Light cases is that they represent the first major implementation of TOD pricing in Wisconsin. Whereas MG&E II limited TOD pricing to two major customers, in Wisconsin Power & Light the Commission ordered TOD rates for large industrial and commercial customers, together with a study on the impact of these rates.

To make its decision in this case the Commission considered five cost-of-service studies as well as proposals by the utility, staff and environmental groups.

After due consideration the Commission proposed a rate which was mandatory for all commercial and industrial customers using over 500 kW

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[1]For selected typical electric bill comparisons, see Appendix D.

in at least eight of 12 months. For customers between 200 kW and 500 kW, the TOD rate was optional. Optional customers, having chosen the rate, had to remain on it for at least one year. However, the Commission ordered that TOD meters were to be installed for all customers above 200 kW, with the cost of such meters to be recovered through a $12.50 monthly metering charge.

The pricing period for on-peak usage was set at 8:00 a.m. to 10:00 p.m. Monday through Saturday, excluding holidays. There was a pricing provision called Off-Peak Excess Demand, which measured maximum demand for "200 kW and over customers" as the highest 15 minute on-peak demand during the month, not, however, to be less than 50% of the maximum measured demand during off-peak hours. This provision was designed to curb excess demand during off-peak hours.

There were two major decisions in this set of cases, and they are discussed in turn.

The 1974 Wisconsin Power and Light Co. Case - Docket No. 2-U-7778

Of major dispute in this case were the proposed charges for the residential tail blocks. The Company proposed an increase relatively larger in the tail blocks than the higher use front and middle blocks but was reluctant to raise rates in the front block sufficiently to cover LRIC.

The Wisconsin Power & Light (WP&L) proposal showed a greater sensitivity to revenue erosion than to the control of demand in the tail blocks. By moving the middle blocks for residential rates virtually to incremental cost, revenue stability would be assured, since this is where the bulk of the class use occurs.

The LRIC study submitted by WP&L, however, indicated that load growth came from increased use by existing customers rather than from new customers. Load growth is thus derived from the tail blocks. The study also indicated that industrial rates required a greater increase than the rates for other classes in order to equal LRIC.

As a consequence, the Commission increased the residential rates between 1% and 10%, with the largest increase in the higher usage front and middle blocks. Industrial demand charges were increased between 23% and 24%, with somewhat more modest increases in the energy charges. In all cases, the increases were levied on the tail blocks, since those were the use categories causing growth and the eventual need for new generating capacity. The rates, as established by the Commission, represented a first step toward LRIC.

The 1976 Wisconsin Power and Light Co. Case - Docket No. 2-U-8085

In this instance, the Commission moved closer to the goals expressed in the Madison Gas cases. There were several cost studies submitted, including both fully allocated cost (FAC) and LRIC. The costs shown by the two major studies are indicated in Table 6.

Table 6: Comparison Of Cost Classification Studies, Wisconsin Power & Light

Cost Classification	FAC	LRIC
Demand (Per kW)	$101.80	$116.27
Energy (Per kWh)	0.904¢	0.84¢
Customer (Per Customer)[1]	$ 26.91 to	$123.51 to
	$32,361.00	$25,000.00

Source: Order, Wisconsin Power and Light

The Commission, on the basis of these studies (which were on a customer class basis), adjusted residential fixed charges to reflect the actual cost and eliminated the special all-electric rate. It also flattened the rate structure. For larger customers, it increased demand charges and also flattened energy charges. In instituting these changes, the Commission noted that the demand charges were still below cost, and that the energy charges were still above cost; but that the movement was in the proper direction.

[1]First number refers to residential: second to industrial.

It was reluctant to move faster for fear of adverse economic impact on existing customers. In short, the Commission arrived at a trade-off among several of its goals.

As listed above, the major action by the Commission was the establishment of a TOD rate for large industrial and commercial customers and the ordering of subsequent study of the impact of these rates on electric usage. This represented the first major implementation of TOD pricing in Wisconsin.

The peak period was defined as 8:00 a.m. to 10:00 p.m., Monday through Saturday, except for holidays. Each customer was to pay a $150 meter installation charge where new meters were needed, and a $15 per month meter charge for 48 months. The demand charge was set at $2.58 kW for the monthly maximum measured peak demand during the peak period. Energy charges were set in two blocks as indicated in Table 7.

Table 7: Peak Period Energy Charges, Wisconsin Power & Light

	On-Peak	Off-Peak
1st 300 kWh	3.24¢	0.85¢
Over 300 kWh	2.23¢	0.85¢

Source: Order, Wisconsin Power and Light (Docket No. 2-U-8085, December 9, 1975)

In addition, a minimum monthly charge of $600 or the maximum monthly demand charge in the preceding 12 months, whichever was greater, was established.

The TOD rates were not to go immediately into effect but were delayed to allow time for such things as metering and changing billing procedures. Further, a subsequent hearing was called to determine what modifications, if any, to the TOD tariff were necessary. Before the hearings, however, studies indicated that 13% of the customers would experience rate increases of up to 300%. In an effort to prevent these low-load factor customers from carrying an extremely adverse economic burden, a limit of 5½¢ per kWh was imposed as the maximum unit charge.

The TOD rates impacted 23% of the Wisconsin retail coincident peak and 25% of the total kWh consumed. The 130 TOD customers had a coincident demand of 198 kW and consumed 1.1 million kWh.

The TOD hearings were to consider the economic, social and physical environmental impact of rate design. Guidelines promulgated for the rates included requirements that they: (1) be cost based; (2) provide fair apportionment of the cost of service: (3) be simple; (4) be free from controversy over interpretation; (5) be capable of producing required revenue; (6) produce revenue stability; (7) assure historical rate continuity; (8) avoid discrimination; (9) discourage wasteful use while permitting justified types and quantities of use. These guidelines were to be reaffirmed in subsequent cases.

Within these guidelines, the Commission examined the questions of rate level and structure as well as peaking periods. The latter were in all cases based on load duration curves and operating characteristics. The period selected had to give the customers an opportunity to shift load and had to provide stable pricing periods. A relatively short peak period provides a greater price incentive for reducing consumption on-the-peak but also has the potential for pricing period instability. The original peak period was held to be the best trade-off.

Examination of the August 1973 peak day load chart for the larger users shows a series of peaks and valleys between 8:00 a.m. to 1:00 p.m. and then a steady decline from 1:00 p.m. The 1973 curve shows a number of peaks between approximately 11:00 a.m. and 6:00 p.m.

In terms of rate level, five cost-of-service studies were introduced. Of these, two were FAC studies by Commission staff and one by Drazen, Brubaker and Assoc. (DBA). The remaining two studies were based on LRIC and were submitted by Foster Assoc. and DBA.

There were two major proposals: one by staff called a Wright-Hopkinson rate that would be mandatory for large customers and optional for smaller commercial and industrial consumers; the other by WP&L which introduced a Hopkinson demand-energy rate with an on-peak, off-peak energy and demand provision.

The staff proposal would have affected 350 customers with demand over 200 kW and incorporated a "stretcher" block with a day/night energy rate.

The Company proposal affected 130 customers with demand over 500 kW. As a result, it would only affect 38% of the customers covered under the staff proposal but would cover 78% of the coincident demand. The Commission felt the Company proposed rate tracked costs more closely than the staff proposal and was simpler, more understandable, and easier to apply.

The established fixed charges were set at $12.50 per month, and demand charges at $5.00/kW for the first 200 kW plus $4.50/kW for demand over 200 kW. Energy charges were set at 2.026¢/kWh on-peak and 1.013¢ off-peak.

This rate was made mandatory for all commercial-industrial customers whose demand exceeded 500 kW per month for eight out of 12 months; it was optional for those with a demand between 200 and 500 kW. TOD meters were to be installed on all customers over 200 kW, with the cost to be covered through a monthly $12.50 fixed charge.

For those customers having a demand of 1,000 kW or more, an optional interruptible rate was provided. All customers requiring 200 kW or more were made subject to an off-peak excess demand provision. Under this requirement, the monthly billed demand is based on the highest measured 15 minutes on-peak but not less than 50% of the maximum measured demand off-peak.

The 5½¢ per kWh rate incentive limit was kept in effect, in order to mitigate abrupt rate increases. It was estimated that 92% of the customer monthly bills would change less than 4% with the maximum change for any customer less than 7% at present consumption levels.[1]

[1] For sample rate schedules, see Appendix E.

WP&L was also ordered to turn in a load-management report one year and one month after the effective date of the authorized TOD rates.

The report was divided into two major segments: a survey of customers and a series of four analyses. The survey involved the mailing of questionnaires to 137 customers. Of these, 84 were returned. The survey indicated the shift in response to TOD was 23 MW. Customers with at least 60 percent of their energy use on-peak and a constant demand experienced no change in their bills. Generally, customers without labor intensive operations, high load factors and three shift operations favored TOD. On-peak type customers, such as department stores, schools, etc., were not enthusiastic. Most of the survey respondents did not like interruptible rates because of the constant nature of their operation. Finally, 50% of the respondents had not been charged under the off-peak excess demand clause.

The survey indicated that 80% of the respondents had analyzed their operation as a result of the rates. Electric melting and holding furnaces, water storage, heat reclamation and refrigeration equipment were under consideration for movement off-peak. Of those replying, 75% were not making special investments to take advantage of TOD rates, 40% had made changes in load operations because of demand and energy charges, 8% changed due to demand charges alone, but none had changed because of energy charges. Thirteen percent had shifted a total of 344 employees off-peak and moved another 32 to a second or afternoon shift. The largest single move was 250 people.

WP&L also conducted four analyses to quantify the effect of TOD. In the energy shift analysis, the data were adjusted to assure its comparability in regard to annual on-peak hours and economic conditions. The conclusion was that usage off-peak increased, and TOD was a major factor.

The noncoincident demand shift analysis showed close to 9% difference in the off-peak to on-peak maximum demand ratio, resulting in 22,458 kW additional per month to the off-peak period compared with 1973.

The third analysis used two methods to determine the monthly system peak response to TOD customers: first was analysis of the change in the TOD rate class system peak load curves from 1973-1977; second was use of the average noncoincident demand multiplied by a coincident factor. Under the first method, the average on-peak use on the August peak day was 89% of maximum demand for Cp-1 in 1977, 90% for the sample in 1977 and 88% in 1973. The off-peak use was 66% for Cp-1 customers, 70% for the sample in 1977 and 56% in 1973. Under the second system, assuming an 85% coincidence factor, the average demand shift on peak days was 19 MW. This indicates that TOD customers have altered their peak day use pattern.

The fourth analysis involved changes in the monthly system peak day load curve. This was flattened, based on the change in the optimum shift pattern.

The Company concluded that TOD customers shifted 79,000 MWh to the off-peak period, moved 22 MW of noncoincident maximum demand and shifted an average of 19 MW on system peak days. This analysis supports the results of the customer survey.

WP&L indicates the cost-benefit break-even point is 0.25% shift in coincident demand to the off-peak. Large industrial customers shifted more than this.

On the other hand, residential costs pose problems. Residential meters have a total cost of $194 and a levelized annual cost of $31. No administrative costs were included in this analysis, although they are believed to be significant. Assuming the average residential coincident demand at 1.25 kW and annual usage at 6,000 kWh, the marginal demand cost equals $189/kW/year and the on-peak - off-peak cost difference is 1.75¢/kWh.

The required shift in kW and kWh for break even would be 9.1%. This would mean a shift of 0.11 kW off the coincident peak and 546 kWh/year to the off-peak period. The value of the shift would be $29.75 or 4% below the annual meter cost.

WP&L concluded that many residential loads are such that it is difficult for residential customers to respond to TOD without expensive timing devices. This would indicate such thermostatically controlled areas as water heating, air conditioning and space heating.

The Federal Residential Experiment: Wisconsin Public Service Corporation
(Docket Nos. 6690-UR-1 and 6690-ER-5)

This case is unique in that it was derived from a proposal submitted by Wisconsin Public Service Corp. (WPSC) and the Wisconsin Public Service Commission to the United States Federal Energy Administration (now the Department of Energy) for funding for a five-year pricing study. In this case the Commission subsequently made the study mandatory for certain classes of customers.

There were several goals expressed as part of the study:

(1) To determine the feasibility of various definitions of on- and off-peak periods and the use of three- versus two-part rates. "Feasibility," the Commission said, "related to the ability of customers to understand such rates coupled with a decision that the benefits outweigh the costs in both economic and social context."[1] The WPSC staff note that updated data (Wisconsin E.P. Docket 6630-CE-12) give a different picture. The peak to off-peak cost differential is 6.9¢ per kWh; in the winter it is 3.9¢ per kWh. The staff state that taking an installed new cost of $95 (Cutler-Hammer), the monthly metering cost is $1.35. In order to break even 35 kWh a month would have to be shifted from peak to off-peak during winter months. During summer months 20 kWh would have to be shifted. Thus a cost analysis on space-heating

[1] Charles J. Cicchetti, Marginal Cost Pricing; The Transition from Theory to Tariffs, p.1.

customers indicated a $3\frac{1}{2}$ year payback period through energy savings through the purchase of a storage heater.

(2) To determine the effect of TOD pricing on demand and consumption of electric water heating, space heating and air conditioning, and

(3) To estimate the "time-of-day elasticity" of demand.

The experiment design consisted of the selection of participants, the definitions of on- and off-peak rates and periods and the assignment of participants to groups.

The groups included a flat-rate initial group; a three-part rate group whose rate consisted of a customer fixed charge, a flat-rate energy charge and a demand charge determined by the maximum monthly peak period power demand; and a two-part rate group without demand charges. There were also different peak hour definitions and different forms of demand and energy charges. Altogether, there are 24 different groups in a rather complex experiment.

Before the experiment, however, the Commission considered pricing policies in a number of cases.

The Build-Up

In its request for rate relief filed with the Wisconsin Public Service Commission, Docket No. 2-U-7779, on August 3, 1973, the Wisconsin Public Service Corporation (WPSC) proposed an equal percentage adjustment to its current rate schedules (with the exception of the electric space-heating rate) to recover its reported revenue deficiency. WPSC did not prepare its own incremental cost study but referred to the long-run incremental cost studies presented in the first Madison Gas and Electric case and the Wisconsin Power and Light case, both of which were pending at the time. It stated that the incremental cost figures presented in those studies were in proximity to the costs of its own system. WPSC also observed that its proposed rates would cover the incremental costs of providing service.

In its Findings of Fact and Order, dated March 15, 1974, the Commission noted that the two cost studies referred to by WPSC differed greatly in methodology and in results and were meaningless in drawing any conclusions about WPSC's cost levels. In order to determine if the Company's rates reflect incremental costs of service, the Commission ordered WPSC to prepare and submit a long-run incremental cost study within one year of the date of the Order. The Commission also modified the Company's rate proposal by increasing the share of the revenue increase to be derived from industrial customers, by increasing the fixed charge portion of the rates by a greater than average percentage to reflect more closely customer-related costs and by flattening the rates by increasing the charges in the tail blocks a greater percentage than those of the other blocks. The Commission also increased the charges for the final block of the WPSC's all-electric rates (which apply primarily to space-heating customers and improve the Company's system load factor) by a slight amount in order to ensure that these rates cover the incremental costs of service.

The Wisconsin Public Service Corporation filed an application with the Commission on May 22, 1974, for permission to increase its rates for retail gas and electric service on both a permanent and interim basis. The Commission granted temporary rate relief to the Company through operation of a uniform surcharge applied to the current rates, pending outcome of the second phase of the proceeding.

During the second phase of the hearings in Docket No. 2-U-8016, WPSC presented cost-of-service studies based both on long-run incremental costs and on embedded costs. The cost studies, however, disagreed. The LRIC study produced a revenue excess. The embedded cost study produced a revenue deficiency. However, revisions of that study, performed by the Public Service Commission Staff, showed that the revenue requirement could be met. WPSC also stated that there are difficulties in attempting to design rates based on incremental costs and suggested that its rate structure be based on the traditional embedded costs of service.

The Commission rejected WPSC's proposal, stating that it considered peak, off-peak pricing to be the proper pricing philosophy to move toward. The Commission also stated that the proportional responsibility method of capacity cost allocation presented by WPSC is primarily an equity concept, whereas the peak responsibility method is primarily an economic efficiency concept and is compatible with marginal cost pricing. The Commission considered the peak responsibility method the more appropriate approach in the current economic climate.

The Commission authorized changes in the residential and farm rates producing a flat-rate design for consumption in excess of 200 kWh per month in the summer and a lower rate for usage over 1,500 kWh per month in the winter. The fixed charge portion of the rates was also increased to reflect more accurately the fixed costs associated with the various classes of service. The interruptible water-heating rate was not increased, since it was expected that this schedule would provide some incentive for off-peak usage and thereby improve the system load factor. Also, the space-heating rate schedule was closed to new customers in anticipation of those rates gradually being merged into the general residential rates, and the street-lighting rates were altered to reflect more accurately the costs of rendering service. The Commission accepted and authorized the proposal of the Company to increase the charge for reconnection to $10 during regular hours and $20 after regular hours, and to change its line extension rules by reducing the amount of free extension and increasing the costs associated with contributory extensions.

In a supplemental Order to Docket No. 2-U-8016 dated March 3, 1975, the Commission, stating a need to know the impact on both the utility and its customers of changes in the level of use which might arise from changes in the pricing of electrical energy, ordered WPSC to prepare and submit jointly with Madison Gas and Electric Company a study indicating the feasibility and effect on customers of various forms of time-differentiated and load-rate pricing. It was also ordered that the study include consideration of interruptible service and time-of-day metering and be presented to the Commission within 60 days of the date of the Order.

In Docket No. 6690-UR-1, the Commission granted WPSC interim rate relief on December 12, 1974, through a surcharge to be applied to all electric and gas rates. The Commission also ordered the Company to proceed with its FEA sponsored time-of-day experiment, described below.

During the second phase of the hearings, the Company did not present a specific cost-of-service study but relied on the cost-of-service studies presented to the Commission on September 16, 1974, as ordered in Docket No. 2-U-8016. The Company suggested that these studies were sufficiently recent to be useful in developing rate design in the current proceeding. In seeking a rate increase, the Company proposed that its rates be adjusted on a uniform basis in accordance with its interpretation of the previously presented cost studies.

The Commission staff presented both a long-run incremental cost study and an embedded cost-of-service study and agreed with WPSC that a uniform surcharge to existing rates was appropriate if used only to determine revenue requirement by customer class.

The rates authorized by the Commission reflect a continuing move toward marginal cost-based rates. The rate schedules were flattened, seasonal variations in demand charges were added and the demand and fixed charges were increased to recover in a more appropriate fashion the costs of service as indicated by the staff's LRIC and embedded cost studies.

These three cases, however, were merely preliminary to what followed in the federally funded pricing experiment.

The Pricing Experiment

In February 1975, the Wisconsin Public Service Corporation submitted a proposal, in response to the MG&E order, for a limited study of time-of-use pricing for residential customers. The original proposal was to be implemented for large-use residential customers only, and experimental rates were to be in effect for a one-year period. This proposal was expanded into a joint project involving the WPSC and the Commission in a larger, more sophisticated analysis of TOD electric rates. The revised proposal was submitted to the Federal Energy Administration's Office of Utilities Programs in a request for partial funding in connection with that agency's involvement in testing alternative approaches to electricity pricing.

Federal funding was approved for the proposal in September 1975. The revised experiment was to last four years and was to include approximately 700 randomly selected participants from high- and intermediate-use residential customers. The experiment was to employ several different time-of-use pricing structures and a standard control rate. Consultants from the fields of economics and econometrics, statistics, social psychology, research methodology and field experimentation were retained to aid in the experiment.

The goals of the experiment as developed by the Commission and Company staff, and reported in Docket No. 6690-ER-5,[1] are as follows:

(a) To determine the feasibility of various definitions of on- and off-peak periods and the use of three- versus two-part rates. Feasibility relates to the ability of customers to understand such rates coupled with a decision that the benefits outweigh the costs on both economic and social context. Because it is believed that the high-usage customers have a good probability (relative to the low-usage customers) of meeting these criteria, the high-usage customers are more heavily sampled in the experimental design.

(b) To determine, to the extent feasible, the effects of time-of-day (TOD) rates on the usage--both demand (kW) and consumption (kWh) of electric water-heating, space-heating, and air conditioning customers. This goal is based on the view of the probable future importance of these customers as a major component of residential load.

[1]Public Service Commission of Wisconsin, Findings of Fact and Order Establishing Temporary Experimental Rates, Docket No. 6690-ER-5, February 18, 1977.

(c) To estimate the effects of time-of-day prices on electrical demand (kW) and on electricity consumption (kWh). The technical economics term for an estimate of the effect of time-of-day prices is "time-of-day elasticity."

It was also decided to collect a year of "baseline" data on the electric usage patterns of the customers chosen for participation in the experiment under the electric utility tariffs currently in existence. On December 3, 1975, the Wisconsin Public Service Commission issued an interim order in Docket No. 6690-UR-1 which directed the WPSC to:

> ...begin a time-of-day pricing experiment and install recording meters at the premises of approximately 700 customers to obtain the required measurements; and that special experimental rates shall be submitted to this Commission for approval and implementation.

In accordance with the goals established for the rate experiment, several econometric models were developed to measure the effect of time-of-use rates on the usage patterns of residential consumers with various combinations on electrical appliances. Using the data obtained from the "baseline" measurement of consumption patterns in combination with the data collected during the imposition of the experimental rates, it was hoped that the econometric models would be able to predict how usage patterns are affected by various peak, off-peak pricing ratios as well as by various household usage characteristics, such as different combinations of electrical appliances, income level, family size, educational level and number of people home during the day.

The Commission ordered in Docket No. 6690-ER-5 that the rates established for this pricing study would be in effect for a period of three years for the participating experimental and control groups. Also, in order to provide a thorough analysis of the effects of TOD rates on residential electric consumption, several definitions of peak period in combination with the different peak versus off-peak price ratios were to be tested. The rates used in this experiment were designed so that if customers do not change their consumption patterns, the average bill for the customers under the experimental rates will be the same as the bill

Table 8: Time-Of-Use Experimental Rates, Wisconsin Public Service Corporation

Schedule Number	WPSC Rate Number	Number Hours On-Peak	On-Peak to Off-Peak Ratio	Urban or Rural	Monthly Fixed Charge	Winter (Nov. - June) Peak Hours (see Note 1)	Winter Energy charge per KWH (see Note 2) On-Peak	Winter Energy charge per KWH (see Note 2) Off-Peak	Summer (July - Oct.) Peak Hours (see Note 1)	Summer Energy charge per KWH (see Note 2) On-Peak	Summer Energy charge per KWH (see Note 2) Off-Peak
Rg-EU3	011	6	8:1	U	4.94	9a.m.-12p.m. 5p.m.-8p.m.	$.1065	$.0133	9a.m.-12p.m. 1p.m.-4p.m.	$.1266	$.0158
Rg-ER3	013	6	8:1	R	8.99	"	$.1063	$.0133	"	$.1258	$.0157
Rg-EU4	029	6	4:1	U	4.94	"	$.0795	$.0199	"	$.0940	$.0235
Rg-ER4	031	6	4:1	R	8.99	"	$.0794	$.0199	"	$.0937	$.0234
Rg-EU5	037	6	2:1	U	4.94	"	$.0528	$.0264	"	$.0620	$.0310
Rg-ER5	039	6	2:1	R	8.99	"	$.0528	$.0264	"	$.0621	$.0310
Rg-EU6	044	9	8:1	U	4.94	8a.m.-12p.m. 4p.m.-9p.m.	$.0835	$.0104	8a.m.-5p.m.	$.0977	$.0122
Rg-ER6	049	9	8:1	R	8.99	"	$.0830	$.0104	"	$.0970	$.0121
Rg-EU7	054	9	4:1	U	4.94	"	$.0676	$.0169	"	$.0791	$.0198
Rg-ER7	058	9	4:1	R	8.99	"	$.0673	$.0168	"	$.0788	$.0197
Rg-EU8	061	9	2:1	U	4.94	"	$.0490	$.0245	"	$.0572	$.0286
Rg-ER8	063	9	2:1	R	8.99	"	$.0489	$.0244	"	$.0573	$.0286
Rg-EU9	067	12	6.9/7.6:1	U	4.94	8a.m.-8p.m.	$.0688	$.0100	8a.m.-8p.m.	$.0761	$.0100
Rg-ER9	069	12	6.8/7.6:1	R	8.99	"	$.0684	$.0100	"	$.0764	$.0100
Rg-EU10	074	12	4:1	U	4.94	"	$.0601	$.0150	"	$.0664	$.0166
Rg-ER10	077	12	4:1	R	8.99	"	$.0599	$.0150	"	$.0667	$.0167
Rg-EU11	084	12	2:1	U	4.94	"	$.0462	$.0231	"	$.0524	$.0262
Rg-ER11	093	12	2:1	R	8.99	"	$.0461	$.0231	"	$.0526	$.0263

Note 1 - Monday through Friday, except holidays.
Note 2 - Energy Cost Clause. The adjustment shall consist of an adjustment to the on-peak and off-peak price per KWH based on a formula approved by the Public Service Commission. Ratio of on-peak to off-peak fuel adjustment per KWH will equal the on-peak to off-peak ratio of the time-of-use rate for each customer.

Source: Malko, "Developing and Implementing a Peak-load Pricing Experiment for Residential Electricity Customers: A Wisconsin Experience.

would have been under the standard declining block rate. Table 8 illustrates the rates for the experiment. The on-peak to off-peak price ratios were set at 2 to 1, 4 to 1 and 8 to 1; and three "peak periods" were established at six hours, nine hours, and 12 hours. For the winter period, these "peak periods" were established for the hours of 9:00 a.m. to 12:00 p.m. and 5:00 p.m. to 8:00 p.m. (six hours); 8:00 a.m. to 12:00 p.m. and 4:00 p.m. to 9:00 p.m. (nine hours); and 8:00 a.m. to 8:00 p.m. (12 hours). For the summer period the peak hours were established at 9:00 a.m. to 12:00 p.m. and 1:00 p.m. to 4:00 p.m. (six hours); 8:00 a.m. to 5:00 p.m. (nine hours); and 8:00 a.m. to 8:00 p.m. (12 hours). The off-peak price for electricity was constrained to stay at or above the actual energy production cost. In addition to the control group, which was to remain on the standard declining-block rate, additional pricing groups, one using a flat rate and the other a three-part rate, based on power demand during the peak period, were established.

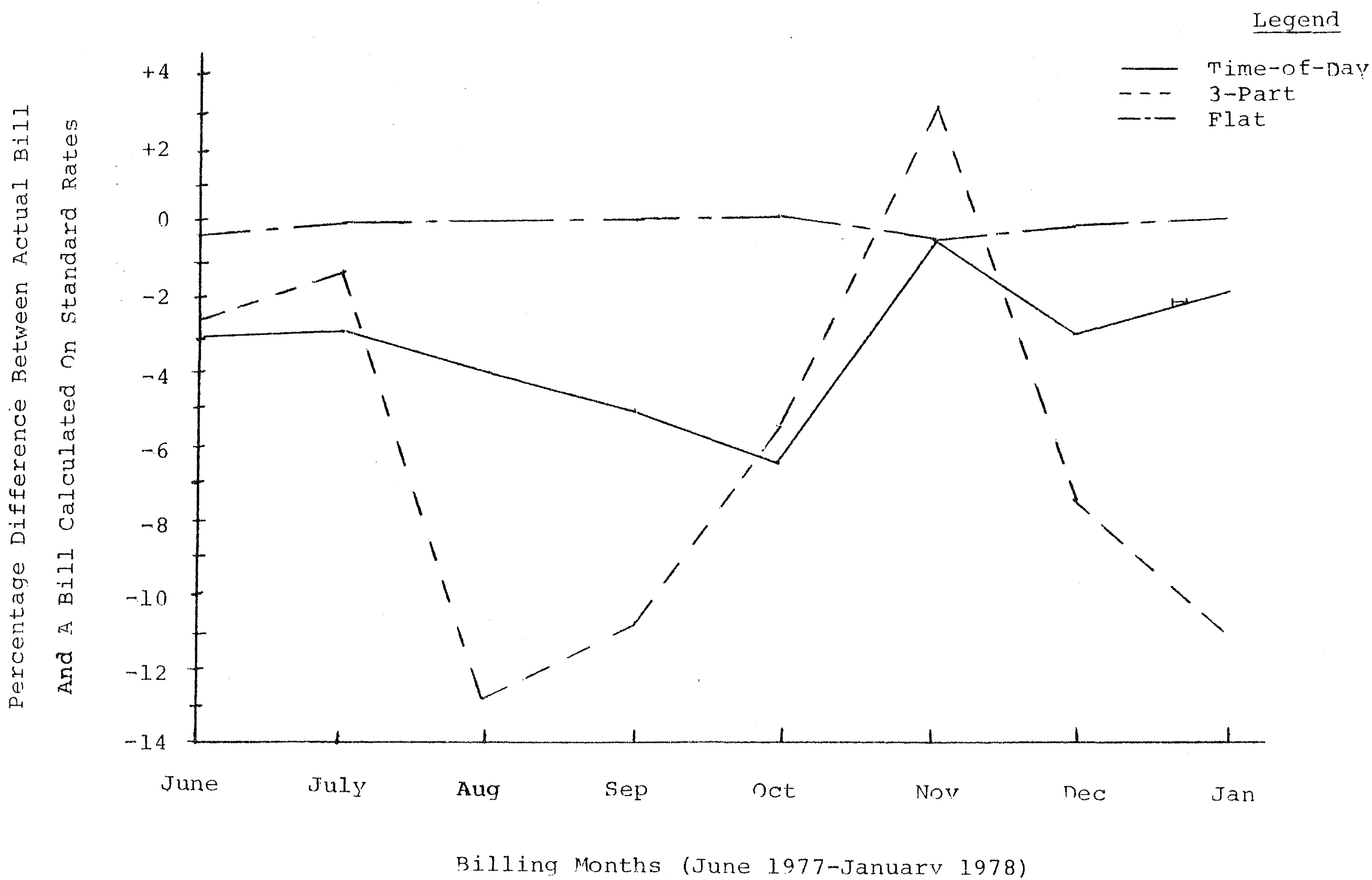
A primary guiding principle to be maintained throughout the rate study was that test conditions should be kept as realistic as possible. This principle placed a constraint on the amount and type of information and guidance provided to the participants in the experiment. However, there was also a need to have enough information about customer usage patterns in order to interpret customer responses to the experimental rates, in addition to the need to have consumers fully understand the new, experimental rate forms. A questionnaire developed by the Commission to survey appliance usage patterns was sent to all households in the experimental, control and standby groups. The customers were paid a $5.00 fee as an incentive to complete and return the questionnaire. A separate survey was also sent to all adult members of the households in the experimental rate groups. The purpose of this survey was to test the attitudes of these participants toward energy conservation, environment, time-of-use electricity pricing and reducing peak period consumption. It was postulated by the research team that these attitudes, in addition to the pricing mechanism, might have an effect on the responsiveness of customers to the TOD rates.

In an effort to approximate the information which would be provided to utility customers in the case of wholesale implementation of time-of-use rates, representatives of the utility visited the experimental households to distribute explanatory booklets, written and graphical descriptions of the rates and written explanations of how customers could alter their consumption patterns to save money on the test rates. Customers also received comparisons of their actual electric bills over the baseline period with what the bills would have been under the experimental rate.

In addition, information was added to the monthly electric bills of consumers in the experimental rate groups to provide an ongoing stimulus to the pricing signal conveyed in the TOD rates. The format of the monthly bill provided to these customers had been altered to show the quantity and percentage of on-peak energy used with the unit and total cost for each; the quantity and percentage of off-peak energy used with the unit and total cost for each; the quantity and percentage of on-peak and off-peak energy used during the preceding month; the quantity and percentage of energy used on-peak and off-peak during the same month of the preceding year and the savings possible from a five percent shift of usage from on-peak to off-peak periods.

The experimental rates have been in effect for approximately one year and, while data collection is still in the preliminary stages, some indication of customer response is available. Since the test rates were designed to produce the same average revenues as the standard rates, assuming no change in customer usage patterns, the average test bill will decline if customers alter their consumption patterns by lowering the average proportion of electricity consumed during the peak periods. For the three-part rate, the average bill will decline if the average customers' demand during peak periods decreases with respect to average total monthly consumption. Figure 1 illustrates the impact of the experimental rates on customers' bills. Comparison of the average customer bill as calculated from the test rates with the bill under the standard declining-block rate for the same total usage showed that the customers participating in the rate experiment have apparently altered their consumption patterns. Thus, the average bills of customers taking service on the time-of-day

FIGURE 1: IMPACT OF TEST RATES ON CONSUMERS' BILLS, WISCONSIN PUBLIC SERVICE CORPORATION



Source: Malk , "Developing a Pricing Experiment" op. cit.

experimental rate have been as much as six percent lower than they would have been under the standard rate. The average bills for customers on the three-part rate have been as much as twelve to thirteen percent lower than they would have been with the standard declining-block rate. However, customers in the control group with an experimental flat rate have experienced average bills at approximately the same level as they would have been under standard rates.

The Wisconsin time-of-day pricing experiment is a direct result of the Commission's decision, as expressed in the Madison Gas and Electric Case I, to move forward in the implementation of TOD pricing for electric utilities within its jurisdiction. The initiation of the pricing experiment shows the Commission's caution in applying TOD pricing to increasing numbers of electric utility customers until the evidence clearly indicates the effects of the pricing methodology on the consumption patterns of electric consumers. However, the pricing experiment currently in progress is far different from the original study which was proposed by the Wisconsin Public Service Corporation.

The original study, as proposed, was to include only residential customers exhibiting high-usage patterns. Customer involvement was to be on a voluntary basis, and the experiment was to be in effect for a one-year period. After the involvement of the Wisconsin Public Service Commission, and with the aid of consultants from various disciplines, the design of the rate study was considerably altered in order to ensure the statistical validity and applicability of its results. Moderate- and low-usage customers were added to the experiment to make the samples more representative of the general customer population. Stratification of the samples according to average consumption levels provided representation of households from all usage levels and allowed oversampling of those households with high-consumption levels. Customer participation was made mandatory in order to remove "self-selection" bias, and the length of the experiment was increased to four years.

It was also important that a decision was made to collect a year of "baseline" or normal usage data. These data were then used to develop the research design to be implemented in the later stages of the experiment. Also, the test rates were designed to collect the same average revenues as the standard rate (assuming no change in usage patterns). Although this decision was mandated at least partially by the legal necessity of preventing rates from being unduly discriminatory, it also eliminated the possibility of customers reacting to changes in their average total bill rather than to the TOD pricing signals. The choice of testing several different peak, off-peak price ratios in combination with various peak periods of six-, nine- and 12-hour lengths allowed the researchers to increase the depth and transferability of the experimental results.

Finally, a decision was made to limit the amount and type of communication with the participants of the study in order to preserve the "realism" of the experiment. Consultations were held with customers before the implementation of the experimental rates during which information concerning the rates was distributed. Information was also added to the customers' monthly bills, and the bill format itself was changed to show the customer consumption patterns. Although this procedure was designed to promote the realism of the experiment, it may prove to be a difficulty when the experiment is completed. Analysis of other experiments has shown that participants react to information provided them during the study as well as to price signals. In the current case, since additional information was not provided to customers in the control groups, it may be difficult to determine to what extent the customers on the experimental rates were reacting to the price signals communicated through the TOD rates and to what extent they were reacting to the information received in their monthly bills. Although this same type of information could easily be provided to customers should a utility adopt wholesale implementation of TOD rates, it might be interesting to see what customer response would be to the rates in the absence of additional monthly billing information.

The rate cases involving Wisconsin Public Service Corporation point out the continuing resolve of the Wisconsin Commission to implement marginal cost time-of-day rates. The Commission continued to move cautiously, through a step-by-step implementation of rate structure reform measures based on cost-of-service studies supplied by both the Company and the staff. Consideration was also given to the anticipated impact of the reforms on the customers of the utility. The recognition of seasonal price differences and the flattening of rates are practices that have been followed by other utility commissions throughout the country in an effort to improve the economic efficiency of utility rate structures. The increases in fixed charges and in demand charges authorized by the Commission are steps toward implementation of cost-based TOD rates since these charges reflect the various customer-related and demand-related cost components of providing utility service. Through its support of, and participation in, the WPSC time-of-day pricing experiment, the Commission recognized the need for more detailed information in further applications of its marginal cost-pricing philosophy.

Residential Customers: Wisconsin Electric Power Company
(Docket Nos. 6630-ER-1,2,5)

Until this point, TOD rates had not been applied to any great extent to residential customers (although residential customers were, quite obviously, an important part of the Wisconsin Public Service Corporation Experiment). In the Wisconsin Electric Power Company case, TOD rates were applied to the 500 largest residential users. In addition, certain small industrial and commercial customers were to be charged TOD rates. Finally, TOD rates were to be mandatory for all large industrial users.

So widespread was the impact of this decision that two of the three Commissioners wrote concurring opinions. Chairman Cicchetti said that the Commission had "progressed significantly."[1] Commissioner John C. Oestreicher went further, "This order reflects by far the most comprehensive implementation of time-of-day pricing in this country."[2] It was quite apparent from the ultimate decision in this case that the Commission was continuing to move forward and expand its commitment to time-of-day pricing.

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[1]Concurring opinion, 6630-ER-2 & 5, p. 24.

[2]Concurring opinion, 6630-ER-2 & 5, p. 30.

The Wisconsin Public Service Commission began a preliminary move toward implementation of time-of-use rates for the Wisconsin Electric Power Company (WEPCO) in Docket No. 2-U-7908/2-U-7951, in which the Commission issued its order dated January 27, 1975. The proceeding was begun on January 17, 1974, when WEPCO filed an application with the Commission for authority to increase its rates for electric service. During the course of the hearings held on the application, testimony was given on a number of issues including advertising expenses, fuel reprocessing costs, construction work in progress, rate of return and rate structure design. In regard to rate structure issues, the rates for electric service approved by the Commission in this case showed a substantial departure from those rates which were currently in effect. The authorized rates for residential service changed the minimum bill from $2.60 per month for the first 50 kWh to $5.00 per month for the first 100 kWh. Also approved was a flat energy charge of 2.35¢ per kWh for all consumption over 200 kWh per month during the summer months (July through October). For the winter months a rate of 1.8¢ per kWh for all consumption over 1,000 kWh per month was authorized in order to recognize the desirable features of increased off-peak energy consumption. The residential all-electric rate schedule was closed to new customers due to its "promotional" characteristics.

The controlled water-heating rate was changed to include $1.00 per month minimum charge and an energy charge of 1.8¢ per kWh (increased from 1.4¢ per kWh). The residential uncontrolled water-heating schedule remained closed to new customers, and the rate was adjusted to bring it closer into line with the general residential rate. The farm rates were changed to reflect a summer/winter price differential, and the industrial rate underwent increased demand charges to reflect more properly the cost burden of customers with poor load factors. The Commission further ordered that WEPCO prepare and submit jointly with Madison Gas and Electric Company a study indicating the feasibility and effect on customers of various forms of time-differentiated pricing, including interruptible service and time-of-day metering.

The more important proceeding followed on May 9, 1975, when WEPCO filed an application with the Wisconsin Public Service Commission for authority to increase its rates for electric service above those rates found to be just and reasonable by the Commission in Docket No. 2-U-7908. In its Interim Findings of Fact and Order, dated September 15, 1975, the Commission granted temporary rate relief to the Company by application of a surcharge to bills rendered for retail electric service, with the intent of addressing the issues of rate design in the final phase of the proceedings.

During the final phase of the proceedings, testimony was given concerning cost-of-service and rate design. However, in its Findings of Fact and Order in Docket No. 6630-ER-1, dated August 5, 1976, the Wisconsin Commission stated that the record in the current proceeding "is insufficient on cost of service studies and rate design, and further consideration will be given these issues in Docket No. 6630-ER-2."[1] The Commission ordered a rate increase for WEPCO by application of a surcharge to the existing base rates and stated that all cost-of-service and rate design testimony presented in Docket No. 6630-ER-1 would be included in the record of the ongoing proceeding, Docket No. 6630-ER-2.

The separate proceeding, Docket No. 6630-ER-2, was established by the Commission's own motion to consider TOD pricing and rate design. On April 26, 1977, the Company filed an application, Docket No. 6630-ER-5, with the Commission for permission to increase its rate for retail electric service. Hearings were held for both proceedings, and the Commission issued a Findings of Fact and Interim Order for both dockets on January 5, 1978. In that order the Commission granted temporary rate relief to WEPCO in conjunction with the implementation of time-of-day rates. The Commission reiterated its commitment to TOD pricing principles, stating that:

[1] Wisconsin Public Service Commission, Findings of Fact and Order, Docket No. 6630-ER-1, August 5, 1976, p. 13.

> ...There is no disagreement among economists or rate engineers that the cost of providing electricity may vary from minute to minute, from hour to hour, day to day, and by season of the year depending on the extent to which the utility's facilities are being utilized....In addition, utility fuel costs per unit of production vary with the level of demands; as demand increases the production cost of additional generating capacity increases because the utility dispatches the generating units in the order of increasing unit production costs.
>
> Time-of-use rates give price signals to the customer as to the cost of producing units of electricity according to the time it is used. Seasonal rates are one form of time-of-use rates. A more complicated form of time-of-use rates recognizes changes in costs by times of day (time-of-day rates).[1]

In stating that electric utility rate design is an "exercise in opinion and judgment" the Commission again listed the criteria and guiding principles it has followed in rate design considerations. (See p. 38 supra.)

Customer class revenue levels were adjusted by approximately equal percentage increases even though cost-of-service studies presented during the hearings indicated that the residential customer class was not paying its full cost of service. The Commission found these rates to be "reasonable and just," because its primary interest was in "reducing peak demand in the summer and changing use patterns throughout the year." To increase the residential customer class rates in accordance with the presented cost-of-service studies would also have resulted in a precipitous price increase for these customers (an increase in rates in excess of 30 percent would have resulted) and would have clouded the price signals communicated to the customer by combining a substantial price increase with the implementation of TOD rates.

Most importantly, the Commission authorized time-of-day rates on a mandatory basis for the 500 largest kWh-usage residential customers, to become effective on July 1, 1978. This authorization was made in accordance with recommendations of both the Commission staff and the Company. Mandatory TOD rates were also authorized for those General

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[1]Wisconsin Public Service Commission, Findings of Fact and Interim Order, Docket No. 6630-ER-2, 6630-ER-5, January 5, 1978, pp. 9-10.

Secondary class customers (small industrial and commercial customers) with monthly consumption in excess of 30,000 kWh for three consecutive months. The TOD rate schedule for these customers was ordered to be accomplished in three phases in order to accommodate meter availability. The larger third of the customers was to be placed on TOD rates beginning July 1, 1978; the second third was to be placed on TOD rates beginning January 1, 1979; and the last third on July 1, 1979. Mandatory TOD rates were authorized for all General Primary customers (large industrial customers), in accordance with recommendations of the staff and the Company.

Peak and off-peak pricing periods were established, based upon an examination of the Company's available capacity, load duration curves and loss of load probability. Consideration was also given to the stability of the pricing periods, and a period of sufficient duration was selected to provide an opportunity for customers to reduce or shift consumption during designated on-peak periods. The staff and the Company were in agreement as to the definition of on-peak and off-peak pricing periods.

Residential customer on-peak periods were established for the hours of 7:00 a.m. to 7:00 p.m., Monday through Friday, including holidays. On-peak pricing periods were established for the General Primary customers during the hours of 8:00 a.m. to 8:00 p.m., Monday through Friday, including holidays. All other times were designated as off-peak. Seasonal pricing periods were set, with the billing months of July through October as the summer or on-peak period, and the billing months of November through June as the winter or off-peak period.

The Commission reported that the authorized time-of-day rates were designed as follows: class revenue levels were set at adjusted current revenue levels; the off-peak energy rates were designed to reflect the system-operating cost, average fuel costs, operating characteristics and voltage losses; the on-peak energy rate was based on these operating cost differentials; the demand charges and the customer facilities charges were adjusted to equal the class revenue level; and the demand charges were designed to reflect the seasonal differential of the cost of service.

The residential rate was adjusted by establishing a flat energy rate, thereby eliminating the existing declining blocks; by applying a seasonal differential to all consumption, with the summer rate approximately 50 percent higher than the winter rate; by eliminating the special block for water heating; by reducing the number of kWh included in the minimum charge from 100 kWh to 40 kWh.

The general primary rate was revised by establishing a flat charge for demand and energy during the summer and winter pricing periods, thereby eliminating all declining blocks; by placing all customers on a mandatory three-part TOD rate; by establishing the on-peak energy charge at twice the off-peak energy charge; and by setting the minimum monthly bill at the charge for 300 kW billed demand plus the facilities charge.

The general secondary rate was revised by authorizing a flat two-part rate for all customers; by placing large customers on a TOD two-part rate for all customers; by placing large customers on a TOD rate schedule for an 18-month period; by eliminating the hours-of-use credit for customers using less than 80,000 kWh per month; and by incorporating a seasonal differential into the rate with the summer rate approximately 40 percent higher than the winter rate.[1]

The Commission stated that the residential[2] and general primary TOD rates should reflect marginal cost as closely as possible, considering revenue constraints. The Commission also decided not to authorize a TOD rate for the remaining general secondary customers, since it had not reached a conclusion on the appropriateness of a three-part (demand, energy and customer charge) or a two-part (energy and customer charge) rate for this group of customers. Hearings will be held in 1978, it was stated, to determine the appropriate rate design for these customers.

Specific rate design issues were not considered during the proceedings for the other classes of customers. All other rates were adjusted by the authorized revenue increases except for the controlled water-heating rate. The Wisconsin Electric Power Company implemented a radio-controlled water-

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[1]For electric revenue comparison of price and authorized rates, see Appendix F.

[2]For residential bill comparison, see Appendix G.

heating load-management experiment for customers under this rate. The results and recommendations from this experiment were to be presented to the Commission in early 1978. The Company also was ordered to prepare an interruptible rate for submission to the Commission, which was to be submitted no later than February 1, 1978.

The Commission, in its order, required the Company to submit a load-management report one year and one month from the effective date of the authorized time-of-day rates. This report is to focus on the impact of TOD rates on:

(1) Customer acceptance
(2) Load shift
(3) System planning
(4) Future load-management applications
(5) Utility cost-benefit analysis
(6) Other relevant information

The WEPCO utility rate cases outlined above continue to show the Wisconsin Public Service Commission's commitment to implementation of cost-based time-of-day rates. During the three-year period in which these proceedings took place, the rate structure of Wisconsin Electric Power Company underwent considerable adjustment. Under the Commission's guidance, the charges for electric service evolved from the traditional declining-block form to a method exhibiting in some fashion virtually all of the characteristics of marginal cost pricing. In authorizing TOD rates for selected segments of the Company's ratepayers, the Commission showed its willingness to move forward in the implementation of marginal cost-based rates as current cost-of-service information and metering technology allow. The Commission's actions also indicate that it is willing to expedite application of TOD pricing methodology where differences between staff and Company exist, or when it feels that progress toward rate structure reform may be moving too slowly.

The revisions made in the residential, general secondary and general primary rates are intended to improve these rates so that they more accurately reflect the costs of providing service. In the absence of detailed cost-of-service and cost-benefit analysis, and with limited availability of metering equipment, the revisions appear to be a good approximation of what is feasible at this time. The summer/winter pricing differential included in the revised rates signals the customer that electricity consumed during the high-usage summer period is more expensive to produce than electricity consumed during the winter period. The flat energy and demand charges eliminate the promotional characteristics of the utility system rather than focusing on the end-use applications of the particular customer. The increase in the minimum bill component of these rate structures serves to separate a portion of the demand and customer-related costs of service from the energy-related cost. This allows the implementation of flat energy charges and provides revenue stability to the utility.

The requirement made of the Company to submit a load-management report to the Commission on the impact of the authorized TOD rates will serve as a source of information upon which to base future rate reform activities. This data and information may be used to expand the implementation of TOD pricing to other customer classes and to improve those TOD rates which are currently authorized.

Stasis: Northern States Power Company
(Docket No. 2-U-8020 and 4220-UR-3)

This last set of cases represents, as noted below, something of a calm spell in the midst of ferment. The Commission did not make major breakthroughs in these cases, but it did continue to deal with the question of rate reform. As of this writing (summer 1978) it has held hearings in connection with TOD pricing but has not actually implemented a final TOD order.

The Northern States Power Company filed an application with the Wisconsin Public Service Commission on May 28, 1974, Docket No. 2-U-8020, for permission to increase its rates for electric service on both an interim and permanent basis. The Commission in its Interim Findings of Fact and Order, dated September 9, 1974, granted temporary relief to the Company through a uniform percentage increase to each customer classification. The issue of rate design was to be taken up in further hearings before the Commission. However, in keeping with its policies established in the Madison Gas and Electric Case, the changes made within each rate schedule were made in the direction indicated by long-run incremental cost (LRIC) studies of other utility companies. Fixed charges were increased by a greater percentage than the overall increase in order to recover more fully customer-related costs, and the last two steps in the rate schedules received a greater than average percentage increase in order to flatten the rates and to bring the energy charge more in line with the level indicated by long-run incremental cost studies.

During the second phase of the proceedings, the Company presented a LRIC study upon which to base its structure. The Commission staff also presented a cost study which produced different results, in terms of customer cost responsibility, than those of the Company. Both of these cost studies indicated that the various rate classes were not properly recovering the costs of service. The Commission determined, however, that it would not be proper at this time to make an abrupt change in the Company's rate design. It authorized rates that moved in the direction of marginal cost pricing by flattening the rates and reducing the number of declining blocks. The Commission noted that in future cases involving Northern States Power Company, it would be necessary to move further in the direction of equating the rates charged for electrical service with the actual costs of rendering that service to the various customer classes.

The Commission authorized the Company to close its all-electric rate to new customers and stated that this rate schedule would be gradually altered to the equivalent of the general residential rates. In the current case, the final block of the various rate schedules was increased to bring it closer to the level indicated by the cost studies. The minimum bill for the various rate classes was also increased, and the residential rate structure was reduced from five blocks to three.

The Commission stated that its intention was to continue increasing the final block until it approximates marginal cost, and to continue flattening the rate design in order to provide the proper price signal to the Company's customers. It further stated that judgment was used in designing the rates in the immediate proceeding rather than following any precise formula of equating rates to costs. Stating a pressing need for more detailed information on the advantages and disadvantages of pricing energy on a peak responsibility basis, the Commission ordered the Company to prepare and submit, jointly with Madison Gas and Electric Company, a study indicating the feasibility and effect on customers of various forms of time-differentiated and load-rate pricing, to be presented to the Commission within 60 days of the date of the order.

On July 16, 1976, The Northern States Power Company filed an application with the Wisconsin Public Service Commission for authority to increase rates for electric and natural gas service. The Commission granted an interim rate increase for electric service on March 3, 1977, pending completion of the case. On January 10, 1978, the Commission issued a Findings of Fact and Order in Docket No. 4220-UR-3 in which it granted the Company rate relief for both electric and natural gas service and implemented further rate structure reforms.

During the proceedings the Company presented an embedded cost-of-service study and a long-run incremental cost study to be used as guides in establishing rate design. As in the previous case, Docket No. 2-U-8020, the cost-of-service studies indicated that the various classes of rates were not properly recovering costs. The Commission again decided that it was unreasonable to make the abrupt changes in rate design which were indicated by the cost studies because of the adverse economic impact on the various customer classes. In this vein, the Commission alluded to the nine rate design criteria which are the basis of its actions.

At the time of the rate proceeding, the Company had six residential rate classifications and two farm rates available to customers, depending upon various rate zones and on whether or not the customer qualified for an all-electric rate. The Company proposed to combine the all-electric and regular residential service rates but to retain the existing rate zones. The proposed combined residential rate would include increased fixed charges to recover more of the customer-related costs, and a declining energy block structure similar to the existing rates. The Company also proposed that the combined rate contain a lower seasonal rate for residential electric space-heating consumption over 800 kWh per month during the months of October through May.

Commission staff proposed to eliminate two of the six residential rates; to retain the all-electric residential rates for existing customers; and to eliminate the all-electric farm rate by combining it with the regular farm rate. Staff further proposed to increase the fixed charges in the rates to reflect the cost differences indicated by the cost-of-service studies and to flatten the energy block structure by reducing the number of blocks and the rate differential between blocks. The Commission staff did not agree that the Company's proposed space-heating rider was cost-justified and also stated that the all-electric rate should remain closed to new customers and should be substantially increased to facilitate a merger with the regular residential rate.

The Commission adopted the rate design essentially as proposed by the staff with the modification of a reduction in the fixed charges to allow for more revenue recovery in the energy block.

At the time of the proceedings, the Company had four rates available to small commercial and industrial customers, differing for urban and rural service territories and for regular and all-electric service. These rates consisted of a fixed charge, a declining-block energy charge structure and included a credit for high-load factor customers with demands in excess of 10 kW. The Company had two demand-energy rate schedules for large commercial and industrial customers, with declining block structures for both the demand and energy charges.

The Company proposed to retain the basic rate structure of the small commercial and industrial rates and to eliminate the all-electric rates for this customer class by transferring the all-electric customers to the regular commercial and industrial rates. The Company also proposed to increase the demand charges of the large commercial and industrial rates to a greater extent than the energy charge in order to reflect the larger increase in demand-related costs.

The Commission staff presented major revisions for the small commercial and industrial rates. The staff proposed the implementation of a demand charge for customers with demand in excess of 10 kW and the limitation of the rate to customers with demands below 500 kW. Also, the number of energy block charges was to be reduced from six to two. In order to mitigate the effect of the demand charge on the low-load factor customers, the staff proposed to limit the increase of the demand-energy charge portion of the rate to 5.5¢ per kWh. The staff agreed with the Company's proposal to eliminate the all-electric rates and to combine them with the regular small commercial and industrial rates.

In regard to the large commercial and industrial rates, the staff proposed to increase the demand charges of the Cg-7 rate to a greater extent than the energy charges in order to recover more of the demand-related costs. The staff also proposed to reduce the number of demand and energy block charges, resulting in a two-step demand charge and a single energy charge. The Cg-7 rate was to be limited to customers with monthly demands less than 1,500 kW. For the CpO-2 rate (for customers with monthly demands in excess of 1,500 kW) the staff proposed to implement an off-peak excess demand provision and an interruptible rate rider. These time-of-use demand provisions were designed to provide incentive to CpO-2 customers to shift peak period loads and to interrupt loads which can reduce system peak demands. The staff also proposed to change the billing procedure for the demand charges from a Kva basis to billing on kW with a power factor correction.

The Commission stated that it would adopt the rates as proposed by the staff on the basis that they more properly reflect costs of service and would therefore provide a more appropriate price signal to the customers than would the rates proposed by the Company. The Commission also stated that it expects this rate structure to be further changed in the future.

In regard to the other rates of the Company, the Commission authorized a substantial increase in the municipal water-pumping rate and flattened the rate structure by reducing the number of energy block charges and also by reducing the rate differential between blocks. The street-lighting rates were revised on an individual lamp size and type basis to reflect changed cost patterns. The commercial heating and cooking rate was eliminated with the customers transferred to the appropriate commercial rate. The energy charges of the water-heating rate were significantly increased to reflect the costs of service. The Company requested that this rate be retained for the purpose of conducting a controlled water-heating service rate experiment.

The Company also proposed to implement a $10 connection charge to recover the costs of new service applications. At the time of the hearings, the Company had no charge for new service applications. The Commission determined that the charge was just and reasonable and reflected the costs of providing new service, and it authorized the Company to implement the connection charge for both its electric and natural gas customers.

Time-of-Day Rates

Detailed time-of-use cost data were not available from the Company at the time of this proceeding, although time-of-use metering equipment had been installed for large industrial (CpO-2) customers and was in the process of being installed for other customers with demand over 500 kW. The Commission, therefore, ordered further hearings to begin on April 15, 1978, for the limited purpose of developing a more complete time-of-day rate design for the large industrial and commercial customers. In regard to future rate structure reform activity, the Commission ordered the Company to implement a load research program to study load and cost-of-service characteristics of its various types and sizes of customers. The program is to be designed to enable development of TOD rates for industrial and commercial customers with demands in excess of 500 kW and to sample metered customers with demands in excess of 200 kW for development of TOD rates. The Commission also asked the Company to perform research and provide the Commission with revenue impact data and operational characteristics of the demand ratchets in the Large Power Service (CpO-2) rate authorized in the current case and to investigate the feasibility of other forms of physical load control and alternate complementary rates, such as interruptible rates, and submit the results to the Commission.

The rate cases outlined herein show some lack of resolve on behalf of the Company toward implementing TOD rates. Indeed, the Wisconsin Public Service Commission seemed to exhibit less urgency in implementing TOD rates for Northern States Power Company than for some of the larger utility companies within its jurisdiction. The Northern States Power Company did, however, present some interesting circumstances to the Commission in implementing its marginal cost TOD pricing policies.

Three years passed between the Commission's order in Docket No. 2-U-8020 and its order in Docket No. 4220-UR-3. In both proceedings, cost-of-service studies completed by the Company and by the Commission staff indicated that the various classes of customers were not properly covering the costs of providing service. Also, in both proceedings, the Commission chose not to alter substantially the Company's rate structure, but rather to move toward cost-based rates by authorizing rates that reflected the cost differentials indicated in the various cost-of-service studies. In taking this action, and being bound by statutory requirement to be nondiscriminatory, just and reasonable, the Commission relied on its judgment in weighing the various rate design criteria. In general, the Commission authorized rates which increased the fixed charge portion of the rate structure to reflect the customer-related costs of service, eliminated most declining blocks to remove the promotional aspect of the present rates, increased the energy charge portion of the rates to reflect the incremental cost of providing service, increased the demand charge for larger customers in order to recover more of the demand-related costs in the separate charge and initiated a connection charge to recover the cost of new service applications. The Commission also implemented an interruptible rider and an off-peak excess demand provision for the Company's largest customers.

These actions seem appropriate given the lack of detailed information on the effects of TOD pricing on the Company's customers. The Commission's pricing actions move the Company's rate structure closer to marginal costs by attempting to have the rates more accurately reflect the various cost-related components of providing electric service, i.e., customer-, energy- and demand-related costs. The Commission also eliminated many of the rate schedules which separated the various customers according to end-use rather than according to cost of providing service. This action is significant considering the many different rates employed by the Company.

The Commission promised to continue to move forward in implementing TOD rates for Northern States Power Company as cost information allows and signaled the expansion of its activity in the area of rate reform by ordering the Company to study the feasibility of load control devices and interruptible and other complementary areas.

Summary

The Commission decided four major TOD cases with increasing sophistication and scope of order. In MG&E I, the Commission introduced a summer/winter rate differential. Following this, a policy statement declaring the Commission's commitment to TOD pricing was prepared. In MG&E II, TOD pricing was applied to MG&E's two largest customers. In WP&L, a TOD rate was established for large industrial and commercial customers and the Company ordered to prepare a study on the impact of the rates. In WPSC, TOD was extended to certain residential customers in a mandatory experiment.

In addition to TOD orders, the Commission initiated a number of attempts to introduce marginal cost concepts, not only in the four cases described above, but in others such as Northern States Power.

CHAPTER 4

THE WISCONSIN PUBLIC SERVICE COMMISSION AND THE ENVIRONMENT

The changeover in pricing undertaken by the Wisconsin Commission coincided with increased ferment in the environmental area and forced the Commission to confront court challenges to its procedures at a time when it was preoccupied with large-scale rate changes.

On December 4, 1972, in a case seemingly unrelated to TOD pricing, the Wisconsin Electric Power Company (WEPCO) filed a request for a rate increase, and on March 16, 1973, the Commission issued an order authorizing rate increases averaging 5.2%. This order was attacked by Wisconsin's Environmental Decade (WED) on the grounds that in issuing its decision the Commission had failed to comply with the Wisconsin Environemntal Protection Act (WEPA).

WEPA was substantially patterned after the National Environmental Policy Act of 1969 (NEPA),[1] which contains a broad statement of governmental commitment to environmental protection. In addition, WEPA (and NEPA) imposes certain procedural requirements on agencies in making decisions in order to ensure that environmental values are considered.[2]

The most important procedural requirement is that an environmental impact statement (EIS) is to be filed for a major action "significantly affecting the environment." The impact statement must include consideration of:

(1) the environmental impact of the proposed action;
(2) unavoidable adverse environmental effects;
(3) alternatives to the proposed action (including the alternative of not doing anything);

[1] 42 U.S.C. Sec. 4321 et. seq.

[2] For text of the Act, see Appendix I.

(4) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and
(5) any irreversible and irretrievable commitment of resources.

In addition, the Wisconsin Act (but not NEPA) requires:

(6) details of the beneficial aspects of the proposed project, both short term and long term, and the economic advantages of the proposal.

The agency responsible for preparing the EIS must obtain comments from interested agencies with special expertise, must make the EIS available to the governor and the public and must hold a public hearing before making a final decision.

In the previously mentioned WEPCO case the Commission refused to prepare an EIS, concluding that the direct effect of its order was economic; and that environmental impacts, if any, were remote and indirect. In addition, the Commission felt that anything to be said about the environmental impact would be based on mere speculation.[1]

WED's argument was that the WEPCO rates approved in that order would cause increases in electricity demand resulting in increased pollution, more rapid depletion of energy resources and construction of environmentally destructive generating facilities.

WED blamed these hazards on (1) the declining-block rate design, (2) using preferential rates to encourage electric heating of residences, (3) allowing the utility in calculating revenue requirements to include the cost of advertising designed to foster demand and (4) setting rate of return at a level which encourages the flow of capital into the services.

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[1]42 U.S.C. Sec. 4321 et. seq.

As noted, the Commission had not advanced any detailed reasons for not filing an EIS, although two Commissioners advanced some reasons in concurring opinions. The Commission argued that the price elasticity of demand was too poorly understood to predict environmental consequences of different rates; the value of the EIS was not cost-justified considering the effort involved in its preparation; an EIS would be filed at the time future plants might be needed; the Commission already considers the environment when it makes its decision; and no evidence had been presented to the Commission to show a significant environmental effect.

On August 25, 1975, the trial court hearing the case handed down an order requiring the Commission to investigate whether there were adverse environmental consequences before concluding that no EIS need be filed. The Commission and WEPCO appealed, and on July 1, 1977, the Wisconsin Supreme Court issued its landmark decision in Wisconsin Environmental Decade v. Public Service Commission that the Commission was required to investigate the environmental effects of its rate decisions. The Court held that both direct and indirect consequences had to be considered; the burden of gathering evidence on the environmental effects was on the Commission, not on other parties; an analysis of the effect of the Commission had failed to show that usable estimates of elasticity were unavailable; and the fact that an EIS would be prepared for new construction did not mean that such an EIS would deal with the long-range cumulative effect of rate changes.

During the four-year period that this case was in litigation, the Commission began to issue its decisions in the area of marginal cost pricing. Initially, the Commission refused to prepare an impact statement. Thus, in Madison Gas I the Commission concluded without dissent that the rate approval there would not have a significant impact on the environment. A similar finding was made in Madison Gas II and the Wisconsin Power & Light case, although in both cases the Commission announced that it had begun the preparation of a "generic" EIS and had also utilized an environmental screening worksheet to determine whether, in each case, an EIS was necessary. In addition, in the Wisconsin Public Service Corporation Case, decided five months before the Supreme Court decision, the Commission made similar findings using an environmental screening worksheet.

After the Court decision, however, the Commission began to hold that rate changes would have a significant environmental impact, and in the WEPCO decision on January 5, 1978, announced that it would prepare an EIS using its generic statement where possible.

The design of the generic statement and an analysis of the EIS follow below.

On the whole it is accurate to say that the Commission's effort at environmental analysis was not up to the standard of its economic analysis. WEPA forced on an economics-oriented Commission a requirement for which it was not especially prepared. Nor did the Commission hire sufficient staff skilled in the interdisciplinary analysis which WEPA requires.

This confusion and reluctance to confront WEPA is not surprising. Indeed, it parallels the initial awkward Federal experience with NEPA. However, the Commission argues that the technical mission of the Commission, relying heavily on economic analysis and pricing, understandably would lead the Commission to consider environmental and other external costs and benefits, in the determination of rates. It feels that other market distortion can be adjusted by the shadow pricing of inputs. In this way, it contends, environmental impact can be internalized in the rates.

The Commission initially decided to prepare a generic EIS and deal with issues which might be expected to occur in repeated cases, an approach which the Wisconsin Court regarded as a positive approach to the problem.

In spite of the title of generic EIS, the statement ignores several environmental issues and is principally concerned with trying to determine the usage of electricity under different pricing and regulatory schemes designed to promote more efficient usage.[1] The principal determinant of usage was considered to be elasticity of demand, and the WPSC staff, after consultation with economic experts, assumed elasticity functions for different customer classes and computed usage changes for each class under different regulatory alternatives. Finally, after extensive analysis of this sort, the document dealt briefly with physical impacts. Four scenarios were developed for different types of load shifts resulting from changes in the pricing structure or use of load-management techniques. These scenarios were used to predict pollution levels. Although some attempts were made to predict how different economic groups would react to various proposals, no discussion was made of possible adverse social impacts of TOD pricing or other alternatives.

The generic EIS was thus a limited evaluation of environmental consequences. It really can be thought of as a document exploring the economic consequences of differing demand elasticity assumptions which, the Commission had decided in the rate cases, could not be estimated clearly. Obviously it would be useful as a base to build on but was not really a comprehensive impact statement.

Under WEPA, as with NEPA, agencies first prepare a preliminary EIS which is to be circulated to appropriate agencies and the public before a final EIS is prepared. The preliminary EIS is supposed to consider all relevant issues. In the WEPCO case, however, the Preliminary Environmental Impact Report (PER) consisted almost entirely of the environmental screening worksheet which indicated potential environmental effects and concluded that an EIS was necessary. The PER was not, therefore, in any sense a preliminary EIS, since it did not go beyond the worksheet.

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[1]The staff argue that efficient usage, however, is achieved only if social marginal costs including environmental costs, are included in the marginal cost determination (adjusted if necessary for "second-best" considerations). Hence, they feel, environmental issues do not lie outside the application of sound economics.

The PER was followed, after public agency comment, by the final EIS, which, while not completely responsive to WEPA, represented a substantial improvement over the PER.

However, even a quick assessment of the contents page of the EIS reveals that the Commission did not track the WEPA EIS requirements. Thus, while the project was described and some alternatives (but not the null-alternative, i.e., the alternative of doing nothing) were considered, there was no formal discussion of short-term vs. long-term impacts, irretrievable commitments of resources and the like.

A closer look reveals continued concentration on economic issues. Little or no attention was given to social impacts of TOD rates--what is the effect on the social fabric of families whose wage earners are shifted to night work, for example? Alternatives to the proposed action were dealt with in cursory fashion. The main alternatives considered were interruptible tariffs, temperature sensitive rates and rachet pricing. No consideration was given to such a possibility as load management. Lifeline rates as such were not examined, and the effects of TOD on low-income consumers merited only a paragraph. The lifeline rates and impact on low-income earners had been analyzed in the generic EIS using WP&L data. The staff concluded that the impact in the WEPCO service area would be similar; hence they felt that repetition of the study would not be necessary. The null-alternative discussion was limited to one-half page on the impact of the denial of the rate increase. Since a rate increase could have been given without TOD pricing, this brief discussion was not only inadequate but beside the point.

The Commission staff did, however, attempt to determine impacts of rate changes which, they concluded, resulted from two sources. These are changes in generating facility pollutant emissions resulting from altered operating characteristics, and changes in required construction programs. In order to determine these changes one must first predict usage changes which are reflected by modified system load duration curves and modified system peak demand function, both of which result from price changes.

Thus, as with the generic EIS, the WPSC was again faced with the need to determine customers' price elasticities.

The Commission staff developed four alternative methodologies for determining these elasticities. (1) The first possibility was to use the same elasticity figures as were used for the screening worksheet for the 6630-ER-2 rate proposal. However, as was previously indicated, these elasticities were created in the generic EIS on the basis of "common sense" and what little information was considered to be reliable. The resultant figures were thought to be those which were most plausible, but the PSC staff felt it was futile to attempt to use them for comparison purposes on environmental impacts. (2) The second possibility was to use elasticities estimated from the results of Arizona pricing experiments. However, the results of these experiments were felt to be inconsistent, and there was the problem of transferring elasticities from a short (six month) experiment in the Southwest to general policy changes proposed in Wisconsin. (3) The Commission staff considered getting figures from published literature but faced the same problems that had been encountered in the preparation of the generic EIS three years earlier. Little data had been collected with any accuracy and results of the actual rates used in Europe were considered inappropriate because of differences in economic environment. (4) The final proposal was to develop an alternative methodology to evaluate the impacts of rate schedules. Because of a lack of experience, this was not considered appropriate.

The procedure finally followed by the WPSC staff was to alter the load curves from the screening worksheet. This produced three scenarios. Scenario 'A' was created by making a parallel shift of the entire monthly load duration curve. The amount of the shift was determined so that changes in the monthly usage were equal to estimated net changes in monthly consumption. Scenario 'B' left the monthly system maximum demand unchanged. Off- and on-peak consumption levels were changed by altering these two portions of the load curve in accordance with estimated changes in usage which would represent a possible "needle-peaking" reaction to time-of-day rates. Scenario 'C' reduced the monthly maximum demand as much as possible in terms of the estimated change in on-peak consumption. The off-peak portion of the load curve stayed the same as that portion for scenario 'B.'

A computer model was then developed using estimates of generation levels, production costs and pollutant emissions and driven by a demand function of monthly peak demands and monthly load duration curves. Results were given for the current rates and for each scenario for both the WEPCO proposed rates and for the PSC rates. A wide variation in results was found depending on which scenario was applied. There was also found to be considerable uncertainty in the entire process, primarily due to the problem of measuring elasticities, making the various rate proposal scenario results of little if any value for comparison.

All of the above related to attempts to determine short-run impacts. The PSC staff concluded that attempts to quantify environmental effects are difficult, and they should wait until data exist from a controlled experiment in order to obtain statistically reliable measurements. The residential study being conducted by the Wisconsin Public Service Corporation under the sponsorship of the Department of Energy was thought to be a source of appropriate data.

The staff found long-run impact even more difficult to determine than short-run impacts, since rate design is part of a dynamic process where rates determine usage, which in turn determines plant mix, which in turn affects rates, and so on. Thus, calculating long-run impacts becomes a challenging exercise, and the staff can only consider general long-run implications of alternative rate designs and structures.

The WPSC staff also attempted to determine qualitative environmental impacts. To make these determinations it was necessary to consider the structure of usage demand, which varies with the time-of-day as well as with the time-of-year, as previously indicated. The WPSC staff created several scenarios based on possible reactions of customers and the resultant effect on the system capacity. Tables 9, 10, 11 and 12 illustrate results under these scenarios. Their conclusion was as follows: "As long as the variable cost component of a generating facility is less than the total average system variable plus fixed costs, then generating additional energy from that facility will lead to a decrease in cost per unit of energy generated."[1] This can occur as long as off-peak consumption does not increase to the extent that new construction is required. Peaking facilities have a variable cost exceeding average total cost. Since peaking plants are all oil fired, shifting demand from peak periods will mean less reliance on oil and thus fewer nitrous oxide emissions. An increase in off-peak consumption, with or without a concurrent decrease in peak usage, will require more coal base and intermediate generating capacity. If no peak decrease occurs, demand may be leveled, but at a level requiring additional base plant capacity. The fact that some of this increased base capacity might be nuclear-powered (and the implications thereof) was not discussed.

The staff included a discussion in the EIS on the different types of charges and rating periods, but little consideration was provided on the potential environmental effects except in the most general terms. Bill impacts experienced by customers were considered only to the extent that these changes alter consumption sufficiently to affect the system demand. No direct discussion of environmental impacts of these changes was provided. The staff found that too little information is available on the possible effects of various rate design alternatives of interruptible tariffs, temperature sensitive rates and rachet pricing. Thus, environmental effects could not be determined with any validity.

One might well question the importance of the EIS problem here. After all, many other states do not have EIS requirements. Yet there remains

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[1]Wisconsin Public Service Commission, "Environmental Impact Statement for the Proposed Wisconsin Electric Power Company Tariffs for Electric Utility Service, Dockets 6630-ER-2/5," p.33.

Table 9: Short-Run Generation Production Statistics, WEPCO proposed Rates

Estimated Short-Run Effects

	Current Rate	A	Percent Change	B	Percent Change	C	Percent Change
al (10^3 MWH)	16,700	16,735	0.21	16,744	0.26	16,771	0.42
st Summary (10^3 $)							
Fuel	117,312	117,760	0.38	117,394	0.07	117,705	0.33
O & M	17,727	17,746	0.11	17,746	0.11	17,764	0.21
Total	135,039	135,506	0.35	135,140	0.07	135,469	0.32
el Use							
Coal (10^3 tons)	4,080	4,093	0.32	4,093	0.30	4,107	0.66
Oil (10^4 gals.)	1,379	1,422	3.12	1,326	-3.81	1,327	-3.77
Non-Consumptive							
Water Use (10^8 gals.)	7,693	7,711	0.23	7,705	0.17	7,719	0.34
llutants							
Sulfur Oxides (10^5 lbs)	2,941	2,953	0.40	2,946	0.16	2,959	0.61
Particulates (10^4 lbs)	1,620	1,625	0.29	1,628	0.52	1,633	0.80
Carbon Mon. (10^3 lbs)	4,080	4,093	0.32	4,093	0.30	4,107	0.66
Hydrocarbons (10^3 lbs)	1,224	1,228	0.32	1,228	0.30	1,232	0.66
Nitrogen Oxides (10^4 lbs)	7,510	7,538	0.38	7,526	0.21	7,552	0.56
Aldehydes (10^1 lbs)	3,419	3,468	1.44	3,373	-1.36	3,380	-1.14
Waste Heat (10^{11} BTU's)	1,068	1,071	0.24	1,070	0.16	1,072	0.37

A - Assuming a proportional shift in the load duration curve.
B - Assuming monthly system peak usage remains unchanged.
C - Assuming monthly system peak usage is reduced.

Source: Environmental Impact Statement for Electric Power Company.

Table 10: Long-Run Generation Production Statistics
WEPCO Proposed Rates

		Estimated Long-Run Effects					
	Current Rate	A	Percent Change	B	Percent Change	C	Percent Change
Total (10^3 MWH)	16,700	16,822	0.73	16,906	1.23	16,915	1.29
Cost Summary: (10^3 \$)							
Fuel	117,312	118,884	1.34	117,858	0.47	117,726	0.35
O & M	17,727	17,793	0.37	17,828	0.57	17,835	0.61
Total	135,039	136,677	1.21	135,687	0.48	135,561	0.39
Fuel Use:							
Coal (10^3 tons)	4,080	4,124	1.07	4,151	1.73	4,157	1.88
Oil (10^4 gals.)	1,379	1,531	11.02	1,154	-16.32	1,085	-21.32
Non Consumptive:							
Water Use (10^8 gals.)	7,693	7,756	0.82	7,751	0.75	7,751	0.75
Pollutants:							
Sulfur Oxides (10^5 lbs.)	2,941	2,984	1.46	2,970	0.99	2,974	1.12
Particulates (10^4 lbs.)	1,620	1,629	0.56	1,669	3.02	1,671	3.15
Carbon Monoxide (10^3 lbs.)	4,080	4,124	1.07	4,151	1.73	4,157	1.88
Hydrocarbons (10^3 lbs.)	1,224	1,237	1.07	1,245	1.73	1,247	1.88
Nitrogen Oxides (10^4 lbs.)	7,510	7,607	1.29	7,609	1.32	7,612	1.36
Aldehydes (10^1 lbs.)	3,419	3,593	5.09	3,230	-5.53	3,163	-7.49
Waste Heat (10^{11} BTU's)	1,068	1,077	0.84	1,076	0.75	1,077	0.84

Source: EIS for Wisconsin Electric Power Company

Table 11: Short-Run Generation Production Statistics
PSCW Proposed Rates

Estimated Short-Run Effects

	Current Rate	A	Percent Change	B	Percent Change	C	Percent Change
MWH(10^3)	16,700	16,776	.46	16,787	.52	16,780	.48
Cost Summary: (10^3 $)							
Fuel	117,312	118,355	.89	117,880	.48	117,806	.42
O&M	17,727	17,768	.23	17,772	.25	17,768	.23
Total	135,039	13,612	.80	135,652	.45	135,574	.40
Fuel Use:							
Coal (10^3tons)	4,080	4,108	.68	4,112	.77	4,110	.72
Oil (10^4gals.)	1,379	1,490	8.07	1,351	-2.01	1,341	-2.72
Non-Consumptive:							
Water Use (10^8Gal.)	7,693	7,734	.53	7,726	.43	7,723	.39
Pollutants:							
Sulfur Oxides (10^5lbs.)	2,941	2,968	.92	2,962	.71	2,961	.68
Particulates (10^4lbs.)	1,620	1,628	.51	1,635	.94	1,634	.87
Carbon Monoxide (10^3lbs.)	4,080	4,108	.68	4,112	.77	4,110	.72
Hydrocarbons (10^3lbs.)	1,224	1,232	.69	1,234	.78	1,233	.73
Nitrogen Oxides (10^4lbs.)	7,510	7,573	.85	7,563	.71	7,558	.65
Aldehydes (10 lbs.)	3,419	3,544	3.66	3,407	-.35	3,396	-.67
Waste Heat (10^{12}BTUS)	1,068	1,074	.56	1,073	.47	1,073	.47

Source: EIS for Wisconsin Electric Power Company

Table 12: Generation Production Statistics
PSCW Proposed Rates

Estimated Long-Run Effects

	Current Rate	A	Percent Change	B	Percent Change	C	Perce Chang
MWH(10^3)	16,700	17,084.5	2.30	17,103.7	2.42	17,092.3	2.3
Cost Summary: (10^3)							
Fuel	117,312	122,262	4.22	119,978	2.27	119,807	2.1
O&M	17,727	17,930	1.14	17,936	1.18	17,931	1.1
Total	135,039	140,192	3.82	137,914	2.13	137,738	2.0
Fuel Use:							
Coal(10^3ton)	4,080	4,217	3.35	4,227	3.60	4,223	3.4
Oil(10^4gals)	1,379	1,877	36.13	1,269	-7.97	1,256	-8.9
Non Consumptive:							
Water Use (10^8gal)	7,693	7,892	2.59	7,845	1.98	7,838	1.8
Pollutants:							
Sulfur Oxides(10^5lbs.)	2,941	3,070	4.39	3,037	3.26	3,032	3.0
Particulates(10^4lbs.)	1,620	1,659	2.40	1,694	4.57	1,692	4.4
Carbon Monoxide(10^3lbs.)	4,080	4,217	3.35	4,227	3.60	4,223	3.4
Hydro Carbon(10^3)	1,224	1,265	3.35	1,268	3.60	1,267	3.5
Nitrogen Oxides(10^4lbs.)	7,510	7,815	4.07	7,761	3.35	7,751	3.2
Aldehydes (10^1lbs.)	3,419	3,985	13.94	3,382	-1.07	3,369	-1.5
Waste Heat	1,068	1,096	2.62	1,090	2.06	1,089	1.9

Source: EIS for Wisconsin Electric Power Company

an important point. Although environmental factors are cited as advantages of marginal cost pricing, an overall examination of the cases studied makes it clear that the Commission was principally concerned about a commitment to economic efficiency.[1] If the Wisconsin Commission, a reasonably forward-looking commission, was unable to devote resources sufficient to study the environmental questions, then commissions in other states may also be unable to do so. This may well lead to substantial opposition to widespread marginal cost pricing in other states, obscuring thereby the benefits of the Wisconsin approach.

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[1]We do not wish to question the Commission's concern about environmental protection, a concern which it argues has been expressed as recently as the summer of 1978 in the Commission's "Advance Plans for Construction of Facilities" (Docket No. 05-EP-1). In this decision, in which environmental considerations played a strong role, the Commission announced that it found that new commitments to nuclear capacity would generally be imprudent.

Finally, we are not making any judgment as to the legal sufficiency of the environmental impact statement but only noting that certain factors have not been considered with the same depth as others. In this connection, we note that although WED continues to find the statement defective, EDF has argued that it is an adequate document.

CHAPTER 5

AN OVERVIEW OF THE WISCONSIN RATE EXPERIENCE

The Wisconsin Commission established nine criteria to guide its rate reform efforts. The Commission ruled rates must:

(1) be based on time-differentiated marginal costs;
(2) result in a fair apportionment of the cost of service among customer classes;
(3) be simple;
(4) be easy to interpret;
(5) produce the required revenues;
(6) result in revenue stability;
(7) have historical continuity;
(8) avoid discrimination;
(9) discourage wasteful use.

To meet the first two criteria, each case showed a heavy dependence on cost-of-service studies. These usually included both fully allocated cost and various marginal cost methodologies. In the latter instance, the various cases exhibited an evolution from a relatively simple marginal cost method to much more sophisticated marginal cost computational systems.

The variation in method in the several studies introduced in each case allowed the Commission to assure itself that while it moved toward the rate reform goals, departures from the past were accomplished in a gradual manner. Thus, its decisions indicated the awareness that utility rate design is an exercise in opinion and judgment. As a consequence, the cost-of-service studies were used as a guide in rate setting but were tempered with a desire to prevent a radical rise in rates for any single customer class.

A part of the landmark nature of these cases was the extensive use of economists as witnesses and consultants, rather than the more usual accountants and engineers. While this added a new dimension to the evidence, it also eliminated, to a limited extent, the old dimensions. This was particularly true of the first Madison cases and not quite as true for the later cases.

The extensive use of economists in the first Madison case also resulted in what appeared to be a universal consensus of the efficacy of marginal cost pricing. This was more the result of the type of witness rather than a true consensus on the part of all participants.

Aside from this, the Wisconsin experience demonstrated that it was possible to compute marginal costs and apply them to utility rates. In doing so, however, it had to be recognized that such an application required the exercise of judgment and restraint. Further, the new rate structures had to be applied slowly in order to avoid large short-run bill increases for some customers and possibly disrupt the state's economy.

In undertaking the restructuring of its rates, the Commission concentrated chiefly on the economic issues involved, leaving unsettled some questions on the environmental and social impacts. This posed problems in Wisconsin when active environmental and citizens' groups intervened in the process. In other states concentration on economic issues may or may not pose similar problems, depending on the quantity of citizen activity and state environmental laws.

Other factors important to this case included the strong support of the Governor of Wisconsin, as well as the championing of TOD rates by two Commission Chairmen and a positive response to the restructuring from all of the Commission members (save one) during the study period. This posture seems in line with Wisconsin's reputation as a progressive state responsive to reform.

This pragmatic approach was necessary because several of the criteria tended to conflict. For example, the cost-based and fair apportionment criteria conflicted, in some cases, with the historical continuity criteria. The Commission was thus forced to arrive at a trade-off between these. In doing so, it placed a major emphasis on avoiding too radical an increase in charges for any one customer class. The Commission kept pushing ahead, however, by ordering studies on time-of-day rates, load control devices, interruptible service and other complementary type rates. It then proceeded to implement the results of those studies, again tempered by the desire to avoid disruption.

Further, by assuring that the utility's revenue stability was protected and by taking care that the benefits outweighed the costs, particularly in relation to metering costs, it assured a cautious but steady movement toward the rate reform goal while avoiding a serious adverse economic impact on existing customers.

One of the problems resulting from the cost-benefit approach, however, is the heavy emphasis on large customers as those to whom the new rate forms apply. Since these tend to be manufacturers or commercial activities with somewhat limited operational flexibility, there might have been some question as to whether adequate electrical capacity savings were possible. Subsequent studies tend to indicate that the rates will induce sufficient savings and that shifting to the off-peak period is worth the trouble of revamping the rate structure.

Generally, the Commission moved rates closer to marginal costs by seeing to it that these more accurately mirrored costs, as well as through the elimination of those rate schedules that were based on end-use rather than the cost of service. Most important, the Commission instituted increasingly widespread use of TOD pricing. Again this was done on a gradual basis, beginning first with a summer/winter rate differential, then application of TOD to two large companies, and gradually, extension of TOD to larger numbers of consumers, including residential consumers.

Because of the progressive tradition of Wisconsin, generalizations concerning other states are difficult to make. It seems important to stress here that, in spite of its reputation, Wisconsin did two things which can be followed by other states. First, it moved ahead with caution, slowly and with an awareness of the need to avoid sudden disruptions in rates. Second, it relied heavily on expert testimony and, along with that, it required the utilities to study various aspects of the problems presenting themselves to the Commission. These studies included research prior to rate proposals as well as studies analyzing the effects of rate changes. Thus, the Commission made every possible effort to reduce the risk of error. The final results are not yet in, but the procedures followed in Wisconsin can certainly be utilized in other jurisdictions. If other jurisdictions do this, then at least the chances for proper testing and evaluation should be substantially increased.[1]

[1]For a response by the Wisconsin Commission to this report, see Appendix K.

APPENDICES

A. Wisconsin Public Service Commission, Docket No. 01-ER-1, Policy Statement and Notice of Proposed Rule

B. Wisconsin Public Service Commission, Docket No. 2-U-7423, Appendix C, Schedule 1, Distribution of Revenue Requirement

C. Wisconsin Public Service Commission, Docket No. 2-U-7423, Appendix C, Schedule 2, Rate Schedule Comparison

D. Wisconsin Public Service Commission, Docket No. 3270-UR-1, Appendix C, Schedule 4, Selected Typical Electric Bill Comparisons, Madison Gas and Electric II

E. Wisconsin Public Service Commission, Docket No. 2-U-8085, Time-of-Day Rate Schedule, Wisconsin Power and Light Company

F. Wisconsin Public Service Commission, Docket Nos. 6630-ER-2, 6630-ER-5, Appendix B, Electric Revenue Comparison, Wisconsin Electric Power Company

G. Wisconsin Public Service Commission, Docket Nos. 6630-ER-2, 6630-ER-5, Appendix E, Schedule 1, Regular Residential Bill Comparison, Wisconsin Electric Power Company

H. Wisconsin Public Service Commission, Docket Nos. 6630-ER-2, 6630-ER-5, Appendix E, Schedule 2, Time-of-Day Residential Bill Comparison, Wisconsin Electric Power Company

I. Wisconsin Environmental Protection Act, Wisconsin Annotated Statutes, 1.11

J. The Docket Numbers of Major Decided Cases

K. Wisconsin Public Service Commission, Commission Regulatory Policies on Rate and Environmental Issues

APPENDIX A

STATE OF WISCONSIN

PUBLIC SERVICE COMMISSION

Wis. Adm. Code Ch. PSC 115

Docket No. 01-ER-1

Peak-load Pricing/Time-of-Day Rates
For Wisconsin Utilities Providing
Electric Service

POLICY STATEMENT AND NOTICE OF PROPOSED RULE

(August 15, 1975)

This Notice is of a Statement of Policy and proposed Public Service Commission rule.

STATEMENT OF POLICY

By Order dated August 8, 1974, this Commission announced its commitment to the concept of peak-load, time-of-day pricing for electricity.[1/] With the passage of time, it appears that the efforts to implement this newer concept of pricing have been delayed by desires to analyze more thoroughly the costs and the costing methodology associated with establishing these rates and to conduct the attendant load studies to measure more definitively the hourly usage patterns of various customer classes. These efforts appear to have been largely concentrated on the residential class of customers where a question still exists as to the cost

1/ Re Madison Gas and Electric Co., Docket No. 2-U-7423, 5 P.U.R. 4th 28, August 8, 1974.

of metering for time-of-day rates in comparison with the benefits which will accrue to the system through their implementation. It is quite obvious that similar arguments are not valid for the commercial or industrial customers. These customer classes, in most instances, have metering equipment capable of accomplishing time-of-day pricing structures or, at least, metering equipment that is easily modified to serve the purpose.

The experience gained by the French and British indicate that the most substantial reductions in the growth of system peak and improvements in system load factor were achieved through time-of-day pricing for the industrial and commercial classes of service. While electrical systems in this country are not identical to those in Britain and France, there is no reason to believe the results would be much different here. Having this fact in mind, it appears that undue delay is occurring in the implementation of time-of-day rates for industrial and large commercial classes of service.

Unlike experience with industrial and large commercial classes of customers, there has been no final demonstration, through empirical proof, that time-of-day pricing is cost-justified for the very large class of residential customers or the class of small commercial customers. This is true primarily because lack of elasticity information and knowledge of all cost factors makes very difficult a weighing of costs against benefits. However, it is reasonable to believe that, if time-of-day rates are available--even on an optional basis--to the residential and small commercial classes, such availability will provide a stimulus for technological development of customer appliances and equipment which would allow customers to take advantage of low rates during off-peak periods. Also, increased demand for metering devices should cause the development of more sophisticated equipment in quantities creating economies of scale. It is obvious that these technological advances will not occur immediately nor can the degree of economic benefit which may be forthcoming be predicted; however, with the anticipated continual increases in all of the costs of supplying energy, it is very timely to require some type of time-of-day pricing for residential and small commercial customers.

Although there has been much discussion about the theory and methods of measurement of marginal costs for purposes of pricing electricity, the pursuit of these discussions should not deter the implementation of time-of-day rates since such rates are not necessarily dependent upon application of the marginal-cost method. On the other hand, a marginal-cost approach would clearly dictate time-of-day rates.[2/] In any event, time-of-day rates hit at the heart of some of the major problems of the electric industry. These include less than optimal system load factors, onerous capital financing requirements due to continued growth of on-peak use and environmental burden resulting from excessive plant construction.

2/ Cf. Re Madison Gas and Electric Co., supra.

Time-of-day rates should tend to reduce the average cost to customers by improving the efficiency of the utility system. It is obvious that average pricing and promotional pricing, in contrast to pricing at cost, invite the continued growth of sales during peak periods thereby greatly increasing costs to utilities and to their customers. The adverse features of rates which are established on the basis of average monthly usage can be greatly mitigated by a time-of-day pricing structure which is nonpromotional and which properly recovers the cost caused by those customers, both new and old, responsible for the substantial burden of meeting system peak.

Having had the opportunity to consider many facets of the time-of-day pricing question, the Commission has determined that it is now appropriate to adopt a rule on the subject.

The staff of the Commission will undertake to ascertain the need for an environmental impact statement with respect to this rule, pursuant to Sec. 1.11, Wis. Stats.

NOTICE IS HEREBY GIVEN That pursuant to sections 1.11, 195.03, 196.02, 196.03, 196.20 and 196.37, Wis. Stats., and according to the procedure set forth in section 227.02(1)(e), Wis. Stats., the Public Service Commission will adopt a policy statement and rule, created as herein proposed.

Proposed Rule -- The proposed rule constitutes Chapter PSC 115, Wisconsin Administrative Code, reading as follows:

115. TIME-OF-DAY RATE STRUCTURES FOR WISCONSIN UTILITIES DELIVERING ELECTRIC SERVICE.

115.01. APPLICATION OF RULES. (1) All public utilities, whether privately or municipally owned or operated, supplying electric energy and providing electric service in this state, shall comply with and conform to rules set forth in this chapter except insofar as exception may be made by order of the commission as hereinafter provided.

(2) Nothing in this chapter of the Wisconsin Administrative Code shall preclude special and individual consideration being given to exceptional or unusual situations upon due investigation of the facts and circumstances therein involved or to the adoption of requirements as to individual utilities or services which shall be lesser, greater, other or different than those provided in said chapter.

115.02. TIME-OF-DAY TARIFF PROPOSALS. (1) Any applications and evidence submitted by a utility applicant requesting a change in its electric service tariffs shall be considered presumptively deficient if they do not include:

(a) A proposal for time-of-day tariffs for those customers having existing metering capability or present metering capability which can economically be modifiable for time-of-day measurement. Customers included in these categories would be primarily those in the industrial and large commercial classes.

(b) A proposal for time-of-day provisions for residential and small commercial customers, as well as any others not included in (1) (a). A proposal under this subsection should include:

1. A rate wherein all such customers are billed under a time-of-day pricing structure with appropriate metering to measure usage at each time interval, or

2. A rate with a time-of-day pricing structure where metering options are available to such customer if the customer desires to have usage measured at each time interval, or

3. A definitive plan, and schedule of implementation thereof, for determining the cost-benefit relation

of time-of-day tariff structures for such classes of customers together with subsequent action proposals, where appropriate, or

4. Any reasonable alternative plan serving the same ends and acceptable to the Commission.

(2) A substantial burden will be placed upon the applicant utility to successfully rebut by argument and evidence any presumption created by the filing of an application for change in electric tariff structures without meeting the requirements of section 115.02(1).

115.03. MARGINAL AND INCREMENTAL COSTS. All utilities making application for a change in their electric tariff schedules should, in their application, or evidence in support thereof, supply as much information relating to marginal and long-run incremental costs and their reflection in the rate structure as is feasible.

The Commission invites all interested parties, including utility companies, municipalities and representatives of farm, labor, business, professional, or other groups which will be affected by the proposed rule, to submit written comment before September 15, 1975. A public hearing may be held following a review of the comments.

By Direction of the Commission:

Francesca A. Di Lorenzo

Francesca A. Di Lorenzo
Acting Secretary

Dated at Madison, Wisconsin, AUG 15 1975

APPENDIX B

DISTRIBUTION OF REVENUE REQUIREMENT

Schedule 1

The distribution of the revenue requirement between the various classes of service under rates in effect prior to February 13, 1973, existing existing temporary rates and rates authorized herein are set forth below:

Schedule	Revenue from Pre 2-U-7423 Rates	Revenue from Existing Temporary Rates	Revenue from Rates Authorized Herein
Rg-1 Residential	$11,123,138	$11,892,760	$11,894,000
Cg-1 Commercial	10,723,596	11,403,940	11,012,055
Cp-1 Power	4,499,190	4,931,854	5,325,000
Cp-01 Power	34,000	35,393	35,000
Mp-1 Municipal Water Pumping	274,275	293,216	293,000
Sp-1 Oscar Mayer	297,957	319,104	319,000
Mg-1 U. of W.	2,468,744	2,659,205	2,672,000
Sp-2 Capitol Heating Plant	76,113*	76,113	80,067
Total Sub to Design	29,497,013	31,611,585	31,630,120
Rev. from other Sales and other Revenue	635,220	644,948	644,948
Total	$30,132,233	$32,256,533	$32,275,070

*Actually billed with Cg-1 under pre 2-U-7423 rates.

APPENDIX C

RATE SCHEDULE COMPARISON

APPENDIX C - Schedule 2

Schedule and Block	Pre 2-U-7423 Rates	Temporary Rates	Authorized Rates Winter	Authorized Rates Summer
Rg-1				
Fixed charge	$ .75	$1.00	$1.50	$1.50
First 100 kWh	2.85¢/kWh	3.00¢/kWh	2.50¢/kWh	2.50¢/kWh
Next 400 kWh	2.03¢/kWh	2.25¢/kWh	2.20¢/kWh	2.20¢/kWh
Next 500 "	2.03¢/kWh	2.00¢/kWh	2.20¢/kWh	2.20¢/kWh
Next 500 "	1.56¢/kWh	2.00¢/kWh	1.50¢/kWh	2.20¢/kWh
Over 1500 "	1.56¢/kWh	1.64¢/kWh	1.50¢/kWh	2.20¢/kWh
Cg-1				
Demand				
First 10 kW or less	$1.00	$1.50	$2.00	$2.00
Next 490 "	2.20/kW	2.35/kW	2.30/kW	2.60/kW
Next 500 "	1.95/kW	2.20/kW	2.15/kW	2.45/kW
Next 1000 "	1.25/kW	1.30/kW	1.50/kW	2.00/kW
Over 2000 "	.95/kW	1.30/kW	1.50/kW	2.00/kW
Energy				
First 500 kWh	2.85¢/kWh	3.00¢/kWh	2.60¢/kWh	
Next 9,500 "	2.01¢/kWh	2.20¢/kWh	2.10¢/kWh	
Next 10,000 "	1.66¢/kWh	1.60¢/kWh	1.45¢/kWh	
Next 30,000 "	1.33¢/kWh	1.60¢/kWh	1.45¢/kWh	
Next 50,000 "	1.12¢/kWh	1.20¢/kWh	1.25¢/kWh	
Over 100,000 "	1.05¢/kWh	1.20¢/kWh	1.25¢/kWh	
Cp-1				
Demand				
First 10 kW or less	$2.00	$2.50	$2.50	$2.75
Next 190 "	1.85/kW	2.10/kW	2.10/kW	2.25/kW
Next 800 "	1.10/kW	1.35/kW	1.35/kW	2.00/kW
Over 1,000	0.95/kW	1.25/kW	1.25/kW	2.00/kW
Energy				
First 500 kWh	2.85¢/kWh	3.00¢/kWh	2.55¢/kWh	
Next 9,500 "	1.30¢/kWh	1.40¢/kWh	1.70¢/kWh	
Next 40,000 "	1.12¢/kWh	1.30¢/kWh	1.35¢/kWh	
Next 50,000 "	1.12¢/kWh	1.20¢/kWh	1.25¢/kWh	
Over 100,000 "	1.05¢/kWh	1.20¢/kWh	1.25¢/kWh	
CpO-1				
Demand				
First 10 kW or less	$2.25	$2.50	$4.00	
Over 10 "	1.25/kW	1.50/kW	2.75/kW	
Energy				
Per kWh	3.50¢/kWh	3.50¢/kWh	3.50¢/kWh	

APPENDIX C
Schedule 2 - Cont.

Schedule and Block	Pre 2-U-7423 Rates	Temporary Rates	Authorized Rates
Mp-1			
Demand charge			
First 1500 kW or less	$2,220	$2,625	$3,750
Over 1500 "	$1.44/kW	$1.50/kW	$2.35/kW
Energy charge			
First 150 hrs.use of demand	1.33¢/kWh	1,50¢/kWh	
Over 150 " " " "	1.00¢/kWh	1,10/kWh	
Per kWh			1.06¢/kWh
SP-1 Oscar Mayer			
Demand charge			
1st 10% of contract demand	$1.67/kW		
Remaining 90% of contract demand	.85/kW		
Per kW of contract demand		$1.255	$2.00
Energy charge			
First 55 hrs.	2.20¢/kWh	2.20¢/kWh	
Over 55 "	1.00¢/kWh	1.10¢/kWh	
Per kWh			1.06¢
MG-1 U.W.			
Demand per kW	$0.925/kW	$1.25/kW	$2.00/kW
Energy per kWh	0.97¢/kWh	1.05¢/kWh	.90/kWh
Sp-2 Capitol Heat Plant			
Demand per kW		$1.25	$2.20
Energy per kWh		1.11¢	0.90¢

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APPENDIX D

SELECTED TYPICAL ELECTRIC BILL COMPARISONS

Madison Gas and Electric Company

Rate Schedule	Monthly Consumption (kWh)	Interim Rate	Final Rate	Increase $	Increase %
Rg-1	Winter				
	300 kWh	$ 11.57	$ 12.60	$ 1.03	8.90%
	500 kWh	17.93	19.60	1.67	9.31
	700 kWh	23.20	26.00	2.80	12.07
	1,000 kWh	31.11	35.60	4.49	14.43
	1,500 kWh	42.50	49.35	6.85	16.12
	Summer				
	300 kWh	$ 11.57	$ 14.60	$ 3.03	26.19%
	500 kWh	17.93	23.00	5.07	28.28
	700 kWh	24.28	31.40	7.12	29.32
	1,000 kWh	33.81	44.00	10.19	30.14
	1,500 kWh	49.70	65.00	15.30	30.78
Cg-1	Winter				
0kW	1,000 kWh	$ 32.07	$ 36.00	$ 3.93	12.25%
15kW	4,000 kWh	126.63	143.00	16.37	12.93
50kW	12,000 kWh	434.54	501.00	66.46	15.29
150kW	40,000 kWh	1,385.10	1,517.00	131.90	9.52
500kW	125,000 kWh	4,253.05	4,787.00	533.95	12.55
1,000kW	250,000 kWh	8,249.30	9,362.00	1,112.70	13.49
	Summer				
0kW	1,000 kWh	$ 32.07	$ 36.75	$ 4.68	14.59%
15kW	4,000 kWh	128.38	148.50	20.12	15.67
50kW	12,000 kWh	448.54	539.75	91.21	20.33
150kW	40,000 kWh	1,434.10	1,659.75	216.65	15.11
500kW	125,000 kWh	4,424.55	5,253.25	828.70	18.73
1,000kW	250,000 kWh	8,645.80	10,378.25	1,732.45	20.04
Cp-1					
	Winter				
10kW	3,000 kWh	$ 79.56	$ 91.50	$ 11.94	15.01%
50kW	13,000 kWh	421.76	512.00	90.24	21.40
250kW	65,000 kWh	2,025.30	2,415.00	389.70	19.24
500kW	130,000 kWh	3,810.35	4,737.50	927.15	24.33
1,000kW	250,000 kWh	7,182.75	9,167.50	1,984.75	27.63
	Summer				
10kW	3,000 kWh	$ 80.06	$ 92.25	$ 12.19	15.23%
50kW	13,000 kWh	434.26	550.75	116.49	26.82
250kW	65,000 kWh	2,105.30	2,653.75	548.45	26.05
500kW	130,000 kWh	4,002.85	5,263.75	1,260.90	31.50
1,000kW	250,000 kWh	7,600.25	10,268.75	2,668.50	35.11

APPENDIX E

WISCONSIN POWER AND LIGHT COMPANY TIME-OF-DAY RATE SCHEDULE

TIME OF DAY RATE Cp-1 ELECTRIC

Effective in: All territory served by the Company.

Availability

A. This schedule is available for single and three-phase, 60 cycle service. Not available for auxiliary, breakdown, standby, or temporary service except as specified in schedules applicable to such service.

B. Demand Limitation: This schedule is available for any customer over 200 kW and is mandatory for commercial and industrial customers in excess of 500 kW at least 8 of 12 months. For annual review, the end of the 12-month period will be the April meter reading. For customers 500 kW and less, this rate is optional. Optional customers may make application for this rate one year after the effective date, and must remain on the rate for at least 1 year. For new customers, the Company shall, at its discretion, determine the customer's demand limits until annual review of 12 months' service.

C. This schedule will replace, for contract purposes, the previous Cp-4 or Cg-1 rate schedule.

Rate

Fixed Charge: $12.50 net per month

Demand Charge:	1st 200 kW	$5.00 net per kW per month of billed demand
	All kW over 200 kW	$4.50 net per kW per month of billed demand

Energy Charge: (Subject to fuel cost adjustment clause)
2.026¢ net per kWh on-peak
1.013¢ net per kWh off-peak

Pricing Periods:

(a) On-Peak Period - 8:00 a.m. to 10:00 p.m. Monday through Saturday, excluding holidays.

(b) Off-Peak Period - 10:00 p.m. to 8:00 a.m. Monday through Saturday. Plus, all day Sunday, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day (or alternate day designated as legal holiday).

Minimum Monthly Charges

The total net demand and energy billing (after application of fuel price adjustment and discounts) for any month shall be not less than 50% of the highest net monthly demand charge of the previous 12 months.

Terms of Payment

An additional charge equal to 2% of the total charge as billed at the foregoing net rates will be added to the bill if payment is not made on or before 10 days after date of the bill.

TIME-OF-DAY RATE Cp-1 ELECTRIC

Interruptible Rider

See Sheet No. 1

(Appendix B

Schedule 2)

Off-Peak Excess Demand

See Sheet No. 1

(Appendix B

Schedule 3)

TIME-OF-DAY RATE Cp-1 ELECTRIC

Fuel Price Adjustment Clause

See Sheet No. 84

Determination of Maximum Demand

The measured maximum demand in any month shall be that demand in kilowatts necessary to supply the average kilowatts in 15 consecutive minutes of greatest consumption of electricity during each month. Such measured maximum demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero at the beginning of each month.

The average power factor of the customer's load shall be determined monthly from readings registered by watthour meters and reactive component meters, or, at the option of the utility, by means of any standard methods, or meters.

Where standard watthour meters and reactive component meters are used, the monthly average power factor shall be calculated from the respective monthly readings of the standard watthour meter (A) and the reactive component meter (B) according to the following formula:

$$\text{Average Monthly Power Factor} = \frac{A}{\sqrt{A^2 + B^2}}$$

Any reactive component meter used shall be equipped with ratchets to prevent registration of leading power factor.

Determination of Billed Demand

The "Billed Demand" shall be determined each month as follows:

a. When the monthly average power factor is 80% or more, the maximum measured demand shall be decreased 0.5% for each whole per cent increase in monthly average power factor above 80% lagging up to unity.

b. When the monthly average power factor is less than 80% the maximum measured demand shall be increased 1.0% for each whole per cent decrease in monthly average power factor below 80% lagging.

Term

A fixed term of at least 1 year commencing when the utility begins to supply electricity hereunder is required. The obligation of both parties continues after the expiration of such term subject to ten days' written notice to discontinue service, unless otherwise provided by contract.

Any customer who reconnects service at the same premises within 90 days of the time of disconnection is considered as being the same customer and the minimum bill provisions of this schedule, based upon previous use, shall apply from the time of such reconnection.

Conditions

(a) Voltages and Point of Measurement

Service is delivered at only one of the nominal voltages to be specified by the utility, but, at the option of the customer, may be either the standard secondary distribution voltage available, or the standard primary distribution voltage available. Customers requiring more than one voltage must furnish transformation. Ordinarily service will be measured at the delivery voltage, but where necessary may be measured at a different voltage, in which event reasonable adjustment will be made to conform metered quantities to quantities at the point of delivery (except as otherwise provided in this schedule for 33,000 and higher voltage delivery.)

(b) Lighting

When the customer uses electricity hereunder for both light and power purposes, and the voltage variation is such that in the judgment of the customer regulating apparatus becomes necessary, the customer will furnish and install such apparatus at his own expense.

(c) Load Surges and Phase Balance

The customer shall keep its load on the utility's facilities well balanced as between phases of the three-phase supply, and shall control such load in such manner as may be necessary to avoid severe fluctuations or surges, and to avoid causing other disturbances on the utility's electrical system.

TIME-OF-DAY RATE Cp-1 ELECTRIC

(d) Application for Service

In order to receive service at this schedule, the customer shall make written application, specifying the upper limit of demand required and the delivery voltage. A new application is required whenever any of these conditions change.

Discounts of Delivery at High Voltage

Where the customer agrees to take energy at the available distribution primary voltage (which may be either approximately 2300, 4000, 6900, or 12,000 volts, depending upon available facilities) a discount of 5% of the demand and energy charge including fuel price adjustment will be deducted on each month's bill.

Where it is mutally agreed by written contract between the customer and the utility that service shall be supplied hereunder at a voltage of not less than 33,000 volts, an additional discount from the net and gross bills will be deducted for service so supplied. Energy furnished hereunder may be metered either at the delivery voltage, or at the secondary voltage of the customer's first transformation, at the option of the utility. When metered at or adjusted to the delivery voltage a discount of 2 1/2% will be deducted; or, when metered at said secondary voltage without adjustment for losses, a discount of 1 1/4% will be deducted.

Miscellaneous Provisions

The utility reserves the right to determine from what lines service shall be delivered to the customer, and how it shall be transformed to the voltage at which it shall be measured.

It is contemplated that the utility will install without cost to the customer standard equipment incident to rendering the service, in accordance with its standard extension rule. Where extraordinary investment in metering or other facilities is required of the utility, the customer will be required to contribute an amount eqivalent to the difference between the total cost of construction and the cost of an equivalent installation built under standard construction specifications.

APPENDIX F

ELECTRIC REVENUE COMPARISON

Wisconsin Electric Power Company

APPENDIX B

Customer Class	Present Rates	Authorized Rates	Increase $	Increase %
Rg-1 Residential	$145,144,398	$149,323,956	$ 4,179,558	2.90
Wh-1 Controlled Water Htg.				
Residential	436,359	436,199	(160)	0.0
Farm	60,035	59,991	(44)	0.0
Commercial	97,446	97,404	(42)	0.0
Total Wh-1	$ 593,840	$ 593,594	$ (246)	0.0
Wh-2 Unlimited Water Htg., Res.	$ 15,514	$ 16,361	847	5.5
Wh-3 Unlimited Water Htg., Com.	2,336,437	2,403,442	67,005	2.87
Fg-1 Farm	1,689,421	1,740,110	50,689	3.00
Fg-2 Farm All Electric	4,971,262	5,110,679	139,417	2.8
Cg-1 General Secondary	120,477,829	123,932,122	3,454,293	2.87
Cg-2 General Secondary All Electric	6,202,159	6,374,874	172,715	2.78
Cp-1 General Primary	105,690,394	108,520,518	2,830,124	2.68
Ms-2 Incandescent Lighting	5,720,234	5,885,104	164,870	2.88
Mg-2 Municipal Primary	771,162	791,271	20,109	2.61
Ms-3 Mercury and Sodium Street Lighting	3,153,291	3,255,640	102,349	3.25
Ms-4 Ornamental	122,063	125,927	3,864	3.17
Gl-1 Mercury Area Lighting	1,126,458	1,162,186	35,728	3.17
Totals 1/	$398,014,462	$409,235,784	$11,221,322	2.82

1/ Does not include unbilled revenues

APPENDIX G

RESIDENTIAL (REGULAR) BILL COMPARISON 1/
(582,000 CUSTOMERS)

Appendix E
Schedule 1

Wisconsin Electric Power Company

Consumption Per Month (kWh)	Present 2/	Authorized	Increase $	Increase %
Winter (8 months) 3/				
500 kWh	$ 18.69	$ 15.99	$ (2.70)	(14.45)%
1000	33.72	29.99	(3.73)	(11.06)
3000	81.40	85.99	14.59	5.64
Summer (4 months) 3/				
500	$ 18.69	$ 22.29	$ 3.60	19.26%
1000	33.72	43.29	9.57	28.38
3000	93.84	127.29	33.45	35.65
Annual				
500	$ 224.28	$ 217.08	$ (7.20)	(3.21)%
1000	404.64	413.08	8.44	2.09
3000	1026.56	1197.08	170.52	16.61

1/ Residential customer without water heating

2/ Includes 13.16% interim surcharge and .347¢/kWh F.A.C.

3/ **Seasonal Periods:**

a) Usage during the billing months of July through October will be billed at the summer rate.

b) Usage during the billing months of November through June will be billed at the winter rate.

APPENDIX H

TIME OF DAY RESIDENTIAL BILL COMPARISON

Appendix E
Schedule 2

Wisconsin Electric Power Company

Residential (Time-of-Day) Bill Comparison 1/
(500 Largest Customers)

Percent of Usage On-Peak	Present 2/	Authorized	Increase $	Increase %
Winter				
60	$ 81.40	$ 114.20	$ 32.80	40.29%
50	81.40	102.50	21.10	25.92
40	81.40	90.80	9.40	11.55
20	81.40	67.40	(14.00)	(17.20)
Summer				
60	$ 93.84	$ 168.20	$ 74.36	79.24%
50	93.84	147.50	53.66	57.18
40	93.84	126.80	32.96	35.12
20	93.84	85.40	(8.44)	(8.99)
Annual				
60	$1026.56	$1586.40	$ 559.84	54.54%
50	1026.56	1410.00	383.44	37.35
40	1026.56	1233.60	207.04	20.17
20	1026.56	880.80	(145.76)	(14.20)

1/ Based upon consumption of 3000 kWh/mo.

2/ Includes 13.16% interim surcharge and .347¢/kWh FAC

APPENDIX I

WISCONSIN ENVIRONMENTAL PROTECTION ACT

Wisconsin Annotated Statutes

1.11 Governmental consideration of environmental impact

The legislature authorizes and directs that, to the fullest extent possible:

(1) The policies and regulations shall be interpreted and administered in accordance with the policies set forth in this act, and

(2) All agencies of the state shall:

(c) Include in every recommendation or report on proposals for legislation and other major actions significantly affecting the quality of the human environment, a detailed statement, substantially following the guidelines issued by the United States council on environmental quality under P.L. 91–190, 42 U.S.C. 4331,[1] by the responsible official on:

1. The environmental impact of the proposed action;

2. Any adverse environmental effects which cannot be avoided should the proposal be implemented;

3. Alternatives to the proposed action;

4. The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and

5. Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented;

6. Such statement shall also contain details of the beneficial aspects of the proposed project, both short term and long term, and the economic advantages and disadvantages of the proposal.

(d) Prior to making any detailed statement, the responsible official shall consult with and obtain the comments of any agency which has jurisdiction or special expertise with respect to any environmental impact involved. Copies of such statement and the comments and views of the appropriate agencies, which are authorized to develop and enforce environmental standards shall be made available to the governor, the department of natural resources and to the public. Every proposal other than for legislation shall receive a public hearing before a final decision is made. Holding a public hearing as required by another statute fulfills this section. If no public hearing is otherwise required, the responsible agency shall hold the hearing in the area affected. Notice of the hearing shall be given by publishing a class 1 notice, under ch. 985, at least 15 days prior to the hearing in a newspaper covering the affected area. If the proposal has state-wide significance, notice shall be published in the official state newspaper;

(e) Study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources;

(h) Initiate and utilize ecological information in the planning and development of resource-oriented projects.

(3) All state agencies shall review their present statutory authority, administrative regulations, and current policies and procedures for the purpose of determining whether there are any deficiencies or inconsistencies therein which prohibit full compliance with the purposes and provisions of this act and shall propose to the governor not later than July 1, 1972, such measures as may be necessary to bring their authority and policies into conformity with the intent, purposes, and procedures set forth in this act.

(4) Nothing in this section affects the specific statutory obligations of any agency:

(a) To comply with criteria or standards of environmental quality;

(b) To coordinate or consult with any other state or federal agency; or

(c) To act, or refrain from acting contingent upon the recommendations or certification of any other state or federal agency.

(5) The policies and goals set forth in this section are supplementary to those set forth in existing authorizations of agencies.

[1] 42 U.S.C.A. § 4331.

Source:
L.1971, c. 274, § 2, eff. April 29, 1972.
L.1973, c. 204, eff. May 18, 1974.

Administrative Code References
Environmental impact statements, see section NR 150.01 et seq.
Solid waste handling, processing and disposal, see section NR 151.19.

Cross References
Environmental impact statement fees and charges, see § 23.40.

1. In general
Where approximately 99% of proposed right-of-way of urban freeway being financed by state and federal government had been acquired but except for a sewer in the one part of project no actual construction had begun, there were no construction contracts outstanding and the federal approval and authorization for the vast bulk of specific construction projects had not yet been granted, plaintiffs had reasonable probability of success in suit to enjoin construction of freeway on ground that governmental authorities had not complied with the National Environmental Policy Act because of failure to file an environmental impact statement existed and a temporary injunction was issued. Northside Tenants' Rights Coalition v. Volpe (D. C.1972) 346 F.Supp. 244.

Since there is substantial probability that the National Environmental Policy Act was applicable to urban freeway for which no environmental impact statement had been filed and for which there had been no federal approval and authorization for the vast bulk of the specific construction projects involved, court would grant temporary injunction despite argument of government officials that plaintiffs had failed to demonstrate that continued construction of freeway during pendency of action would cause irreparable harm, since it was more consistent with purposes of Act to delay operation at stage where real environmental protection might come about than at stage where corrective action might be so costly as to be impossible. Id.

Wisconsin Environmental Protection Act recognizes an interest sufficient to give a person standing to question compliance with its conditions where it is alleged that agency's action will harm environment in area where person resides. Wisconsin's Environmental Decade, Inc. v. Public Service Commission of Wisconsin (1975) 230 N.W.2d 243, 69 Wis.2d 1.

Under Wisconsin Environmental Protection Act, legislature intended to recognize rights of Wisconsin citizens to be free from harmful effects of a damaged environment where it can be shown that person alleging injury resides in area most likely to be affected by agency action in question. Id.

APPENDIX J

Docket Numbers of Major Decided Cases

Docket Number	Date	Utility
2-U-7423	August 8, 1974	Madison Gas and Electric
3270-UR-1	November 9, 1976	Madison Gas and Electric
2-U-7778	March 8, 1974	Wisconsin Power and Light
2-U-8085	November 12, 1976	Wisconsin Power and Light
6690-UR-1	December 3, 1975	Wisconsin Public Service Corporation
6690-ER-5	February 18, 1977	Wisconsin Public Service Corporation
6630-ER-1	August 5, 1976	Wisconsin Electric Power Co.
6630-ER-2		
6630-ER-5	January 5, 1978	Wisconsin Electric Power Co.

APPENDIX K

Commission Regulatory Policies On
Rate and Environmental Issues

At the request of the Wisconsin Public Service Commission, additional material prepared by the Commission is included here as an appendix.

This chapter is written by the Commission of the PSCW. We undertook this task in order to present our point of view regarding the current Commission's regulatory policy on rate and environmental issues.

The chapters written by the NRRI staff focus on a historical narrative of the regulatory events that occurred leading up to the present. It was prepared when environmentalists split over the final time of day (TOD) tariffs adopted by the Commission. Such arguments are interesting but may prove confusing. The NRRI report may create more questions than answers in the minds of regulators who may wish to pursue the path to TOD rates taken in Wisconsin, because it does not attempt to draw any conclusions to present an analysis or to balance the description of the views of opponents to TOD pricing, therefore a handbook or a prescriptive document that the NRRI report shows the early steps to rates based on marginal costs and the successive improvements along the way. The NRRI staff report is an attempt to present a balanced reporting of events.

The Commission disagrees with several of the implications that may be drawn from the report regarding the appropriateness and practicalities of implementing marginal cost pricing. We also disagree with the implication that the Commission has placed little emphasis on meeting WEPA and NEPA environmental impact requirements and failed to examine societal impacts of regulatory actions.

Consequently we are presenting our philosophy on ratemaking and regulation in this chapter in order to give the Wisconsin story from the Commission's perspective. We apologise for taking up the readers attention with a subject and case that is a special case to the Wisconsin experience, but do not know any easy way to inform other interested states.

During 1972-4, TOD advocates, including the present chairman of the PSC strongly oppose the promotional pricing practices of Wisconsin utilities, which at the time led to a doubling in the construction of electric power plants and their attendant environmental destruction every decade. The Wisconsin Commission in 1974 adopted principles to change such practices in Wisconsin.

The PSCW is categorically opposed to declining block pricing because it promotes energy waste, environmental destruction and can be characterized as foolishly wasteful economics. We support the adoption of time of use pricing, which charges maximum or peak period use penalties for electric power and energy.

Numerous states are now following this advice, at least to the extent of accepting new pricing principles. Chairman Cicchetti has also been active in support of the Congressional adoption of these same principles, as well as having articulated similar policy in Canada.

The Wisconsin Electric Power Company Tariffs adopted by the Public Service Commission of Wisconsin, interim order in docket nos. 6630-ER-2 and 6630-ER-5, while not perfect, are undoubtedly the most comprehensive and advanced time of use electricity tariffs in the country.

The status quo would be disastrous for the environment for two important reasons. First, the existing rates that would remain in effect are highly promotional. They promote electric resistance heating, which is opposed by most environmentalists. They also promote energy use through their declining block provisions. By having these tariffs in effect prior to this spring and summer future electric generation and transmission can be deferred or dropped one year sooner. Additionally, predecisional expenses for other proposed plants in the state would also be encouraged by failure to penalize peak power and energy growth this summer. We believe no environmentalist can want this to happen.

We believe the Commission has fully lived up to the intended spirit of WEPA. It has made an excellent pro-environment, pro-conservation and pro-economic decision. It has studied the proposed changes, their consequences and the alternatives in more detail than any other group, commission or utility in the nation. This has all been sent out as a draft preliminary environmental report. Hearings will be held to learn more, if that is possible. We do not believe we will learn anymore in light of the current state of the art; however, if it is found that tariffs should be changed, the Commission has the regulatory authority, because these tariffs were adopted on an interim basis, to make necessary changes. In my opinion, as a frequent witness for environmental groups in cases concerning WEPA, the Commission has following the full spirit of WEPA and is now following the letter of that landmark legislation.

We believe the Commission has found out all it can, without actually adopting these pro-environment prices, in its generic environmental impact statement and two environmental screens. It is unlikely, therefore, that the final procedural steps when completed by the Public Service Commission of Wisconsin could lead to a change in these tariffs. WEPA could not have meant that nothing should ever be done for the first time! WEPA has been completely followed in spirit. WEPA is procedurally being complied with in the steps taken by the Commission. The Commission's decision and procedure, are both based upon a pro-environment motivation.

Some organizations mentioned in the NPRI study appear to want the Commission:

- to adopt inverted electric rates;
- to adopt temperature sensitive electric rates;
- to stop promoting electric heating;
- to adopt load management and load control rather than time of use pricing.

I. The Commission has retained an inverted electric rate in 6630-ER-2/5. The first 50 kWh of each month's use are provided at a 0¢ per kWh charge. After that each kWh costs the customer 3.3¢ in the eight non-summer months and 4.2¢ in the summer months.

On an annual basis the Commission has changed the relative contribution of each residential customer compared to previous rates so that higher volume users would have the largest percentage increase. Customer use and average price change effects on an annual basis are as follows:

Monthly Use	% Change in Average Price
250 kWh	- 9.87%
500 kWh	- 3.21%
750 kWh	.2 %
1000 kWh	2.09%
1500 kWh	8.74%
3000 kWh	21.04%
5000 kWh	22.96%

The Commission could have made these changes with either a more extensive and complicated inverted rate than the one ordered in 6630-ER-2/5, or a seasonal rate. The Commission selected the latter. While the Commission could have given a lower price to low volume electric users each month to produce the same annual bill as the seasonal rates, the customers' conservation decisions would then only be rewarded at the lower price associated with that low price for the initial blocks. This would have penalized low volume conservers of electricity. The seasonal rates insure that all-electric customers (those using electricity for cooling, heating, and water heating) pay more per unit than lower volume electric users. The seasonal rates give each residential customer an equal saving per unit of conservation. To bring this about all summer rates were raised, but, except for the electric heating customer, all non-summer rates were decreased. The opposition to the final order has occurred during the high priced summer period. However, these same residential rates actually went into effect in January. There was little opposition at that time when nearly all residential rates were reduced until June. In conclusion, the new seasonal rates accomplish much of the cost allocation goals of inverted rates, but, in the minds of the Commission, they more closely relate use and cost for the user to the actual customer consumption decisions.

II. Temperature sensitive rates are the most extreme form of time of use pricing. The on peak prices would be much higher than the present time of use prices. The Commission has not rejected this concept. It simply needs more information on customer response, and metering. The Commission cannot understand why these organizations reject an order that, contrasted to the historic declining block pricing system, is far closer to this goal of temperature sensitive pricing than any other tariff system. This is especially unclear because the Commission has been favorably inclined towards moving in the direction of temperature as well as time sensitive pricing.

III. The rates adopted in 6630-ER-2/5 are the furthest thing from promoting electric heating, yet the opposers either do not seem bothered by numerical facts or do not understand the energy prices of competing sources.

Under 6630-ER-2/5, a new electric resistance heating customer would pay 2.8¢ per kWh in the winter. This would be the equivalent of approximately 59¢ per therm for natural gas, and 75¢ per gallon for fuel oil. Current prices in Milwaukee are more like 24¢ per therm and 45¢ per gallon fuel oil. Obviously, a customer making this comparison would not be drawn to electric heat.

The 577 mandatory time of use customers have already chosen to use large volumes of electricity. 6630-ER-2/5 does not permit an open-ended, wholesale addition to this category. Nevertheless, the 1.3¢ per kWh off peak rate equals about 25¢ per therm of gas for heating, assuming a 100 percent electric resistance heating efficiency and 65 percent natural gas furnace heating efficiency. This means that even for this small number of customers electric heat is not promoted. Electric heating also takes place during peak hours in the winter. For the 577 time of use residential customers, the 5.2¢ per kWh winter daytime price is equal to gas at about $1.00 per therm. If the new rate promotes any heating system, it is solar heat with backup electric storage heating, not resistance heating.

The Commission has ordered WEPCO to purchase 150,000 units of residential load controlling devices. The Commission has also ordered WEPCO to develop 100,000 kW of industrial user interruptible load management. The strategy taken by the Commission is to mix both usage sensitive pricing and load controls to reduce the pressure to build additional power plants at sharply rising prices.

The NRRI study criticizes the PSCW for concentrating on economic issues to the exclusion of environmental issues, but does not take into account:

(a) the Commission moratorium on new nuclear applications;

(b) the elimination of promotional and public image advertising

(c) the Commission's direction on load management and interruptible rates

(d) the promotion of cost-effective cogeration and district heating in the most recent advance plan order (including a novel low cost system for linking up heat from electric plants to the water supply system for water heater savings and low cost space conditioning iwth water source heat pumps.

(e) proposed stiffer insulation standards in the building code for homes heated by natural gas

(f) proposed that the state take action to relieve the effects of high energy bills faced by low income consumers

(g) is taking an active role in the removal of impediments to solar development by expanding the role of utilities

(h) is carrying on an investigation to determine the most economical space heating systems for the future and so as to avoid becoming a future winter peaking state

(i) have developed cost based inverted rates for natural gas customers

(j) has objected to the environmental effects of using the threshold level of pollution for industrial parks rather than a tax on all emissions.

"The Objective

In 1974, the Commission found that the primary objective of utility pricing is that prices, and therefore revenue, should track costs. More formally, utility prices should be based upon the marginal costs of serving additional kilowatts (kW) of power and/or additional kilowatt-hours (kWh) of energy. When prices and costs are "tied" to one another, customer energy savings reduce that customer's bill, as well as both the revenue and cost of service of the utility. Similarly, increases in electricity use would increase the customer's bill, as well as both the revenue and cost of service of the utility. This objective is called economic efficiency by economists and net revenue (or earnings) stability by nearly everyone else. In 1974 the Commission specifically found:

"The Commission Finds":

"1. The principle of marginal cost pricing is an appropriate guide for the purpose of the design rates of Madison Gas and Electric Company and other Wisconsin energy utilities. Such a principle has been shown to be the most effective way to obtain an efficient allocation of resources and to prevent wasteful use of electric energy."

This Commission has used this objective as the corner-stone of 6630-ER-2/5, and the Environmental Defense Fund continues to vigorously support it. However, the Wisconsin Environmental Decade, while it may not completely disagree with the above stated principle, has obviously adopted a new objective and rejects the application of marginal cost pricing. To understand Decade's position a slight digression is necessary.

Stating that marginal costs should be the basis of electricity pricing does not explain much to many people, even economists. To understand the marginal cost of electricity, one has to communicate with the system engineers and dispatchers. Their jobs are respectively to minimize the cost of expanding the system to meet growth in load (capacity), and to minimize the cost of operating the existing system to meet current loads (energy). Minimizing costs to meet demand in the economic sense, or load in the engineering sense, is the logic that leads an economist, who may know little about electricity operations, to conclude that its price should equal its marginal cost.

The marginal cost of electricity varies by time of use and voltage. Time of use may mean season of the year, day of the week and/or hour in the day. Voltage refers to electric pressure.

Generally, large volume electrical users consume electricity at voltages approximately equal to the voltage at which electricity is generated by the utility. Stepping-down voltage, i.e., reducing electric pressure, involves two types of costs. First, transformers must be installed to reduce voltage. Second, stepping-down voltage results in losses in capacity because more kW and kWh have to be generated than are consumed. Lowering the voltage increases both the associated losses and utility costs. Residential users consume electricity at the lowest voltage provided by a utility.

There are two time of use components in the marginal cost of electricity. First, there are hours in the year when demand relative to the available generation and transmission capacity is expected to be high. These are called peak periods. When the latter characteristic is present, demand could be increased without the addition of new capacity. But, during peak periods, increases in demand would lead to system capacity expansion.

Marginal capacity costs in the off-peak is zero, but positive and relatively costly in the peak period. Most utilities can predict the hours in a year in which they expect their peaks to occur. Seasonal, day of the week and time of the day variations are generally observed. Reducing use in peak periods means the utility saves marginal capacity costs of expanding its generation and transmission system prorated to an equivalent kW or kWh basis. Accordingly, one causal component of the time of use variation in marginal cost is the relative expectation of sufficient or insufficient capacity in different time periods.

The second component of the time of use variation in marginal cost is related to the operating side of an electric utility. When demand is low the cost minimizing (or even profit maximizing) utility operates its most cost effective plants nearly exclusively. These are called base load plants. They have the lowest operating costs. As demand increases the utility dispatcher loads additional plants in the order of their operating costs, lowest to highest. During peak periods operating costs are their highest.

Summing up, marginal cost electricity pricing implies different prices dependent upon time of use and voltage. The tariffs in 6630-FR-2/5 are based upon these principles.

Confusion, and now conflict, has come from the fact that while the objective of marginal cost pricing is narrow, there are additional advantages to be derived from marginal cost/time of use electricity pricing. Giving primary status to some, or even one, of these derivative benefits, as we believe Decade has done, may lead to different results.

Generally speaking, in addition to economic efficiency, there are nine derivative benefits expected from adopting time of use pricing:

(1) Cost minimization on the part of the utility is encouraged.

(2) Equity and fairness in the prices charged will be promoted.

(3) System utilization or load factors will be improved.

(4) Environmental damages or externalities will be reduced.

(5) Energy conservation may be improved, and for any specified level of end use electric energy requirements, the energy efficiency of supplying it will be increased.

(6) Earnings stability will be increased as net revenue replaces gross revenue requirements as a more important regulatory mechanism.

(7) Tariff stability will be achieved as pressures for rate increases are reduced.

(8) Consumer freedom of choice will be increased and ways to avoid inflationary rate increases offered.

(9) Contrasted with other rate reforms, namely inverted or all-equal flat rates, industrial and employment interests are protected and stimulated.

This Commission finds these derivative benefits of marginal cost/time of use pricing to be the regulatory equivalent of "icing on the cake." By definition almost, the Commission accepts the economic efficiency reasons for pricing on the basis of marginal cost: (1) in order to signal to consumers the resource allocation/cost consequences of their individual decisions, and, nearly vice versa, (2) in order to signal consumer demand/willingness to pay to the utility to guide investment decisions. The logic of the direct efficiency and the above derivative benefits of marginal cost/time of use pricing seem overwhelming, and by the close of the Madison Gas and Electric case, environmentalists and utilities alike seemed to support the above, and disagreed only about timing.

Decade, in our view, has taken a more narrow objective in placing its doubts before the Commission. Its logic appears to us to be as follows:

(1) System load factor management should be the principal objective of pricing and supplying electricity.

(2) Marginal cost cannot be used to promote economic efficiency because it does not hold true throughout the economy.

(3) Time of use pricing will not save energy or capital, will not be fair, and will encourage base load nuclear technology.

(4) The Commission will not change time of use tariffs because of inertia or political pressures.

(5) Load control is superior because it brings certainty to reduced demand; and, therefore, eliminates the need to expand generation and transmission facilities.

In two other proceedings, namely 6630-CE-12 and 6630-ER-9, the Commission is encouraging load management. In the first, the Commission authorized the purchase of 150,000 load control units for Wisconsin Electric Power Company. In the second, the Commission has required Wisconsin Electric Power Company to establish an interruptible load control tariff for 100,000 kW of industrial use. The Commission's position in 6630-ER-2/5 and these other cases is not consistent. Instead, the Commission finds marginal cost to be the basis for both: (1) time of use tariffs in which the customer manages his/her load in response to price signals, and (2) load control discounts given to the customer who accepts utility management of all or a portion of his/her load. The Commission finds time of use and load control to be complements, both derived from marginal cost. The Decade apparently believes them to be substitutes.

The Commission rejects making "improvements in system load factor" the primary objective for marketing electricity. However, we think system laod factor will improve under time of use pricing. Decade not only wants this to occur, it wants to guarantee it by making improvements in system load factor the principal objective.

If large numbers of people in Wisconsin prefer to pay very large off-peak discounts, then this Commission is prepared to expand the electric system to meet consumer demand provided that the full internal and external costs (to the extent we can measure and include the latter) are charged to those customers causing growth. Decade apparently is not willing to take such a chance.

The vast resources of the economy will start to provide appliances to residential users, and equipment and technology to industry, to take advantage of time of use price discounts. These new options will save utility capacity requirements, reduce utility operating costs and generally mean there will be little or no change in lifestyles. Accordingly, Decade's view is too cautious, and too reminiscent of traditional utility cautiousness and fear of change. However, as already indicated, the Commission is hedging its decision by pursuing a mixed strategy that includes a significant element of load control at the same time that it is phasing in time of use pricing. Both are being based on marginal cost.

Second Best

The Commission further rejects the argument that using marginal cost to determine price is restricted because other sectors of the economy do not use marginal cost pricing. First, to call an economic policy "social welfare maximization," the economist considers all markets in an economy. However, stating one's objective less narrowly, as cost minimization to meet a specific demand for electricity, or, efficiently allocating the resources exchanges in the provision of electricity service, also requires that price be based on marginal cost.

A number of defenders of the status quo in utility pricing have used this same argument against all electricity rate reforms. The Commission does not find this argument to be a serious critique of marginal cost pricing. Further, if accepted, it would be an equal obstacle for both the time of use and load management variations of marginal cost.

The extent that other specific factors, such as low income problems, encouraging employment, discouraging all electric homes, the effect on natural gas, etc. etc. should be included in our tariffs is still open for all parties in our proceeding and the Commission itself to consider. Decade appears to be trying to establish a logical premise for its position on these other adjustments to tariffs while sacrificing marginal cost. Decade's logic is sound, but its objective is too narrow.

Technological Bias

Decade's principal argument against time of use pricing is that it will stimulate new off-peak use through the discount mechanism. This in turn will flatten the utility load curve, result in building capital-intensive nuclear and coal baseload plants, encourage energy-inefficient electric resistance heating, and discourage solar and wind generation.

First, this claim of logic is inconsistent with Decade's implied load factor improvement objective, which leads it to support load control. If a utility controls load, it will also flatten its laod, perhaps even more completely. Any tnedency to relate baseload nuclear or coal to load curves that are flat will, therefore, even to a greater extent, be encouraged under Decade's approach unless the Commission also restricts utility generation plans. Just such a set of restrictions, although not as severe as Decade argued for, are being adopted and have been tentatively approved in draft form in the first Advance Plan (05-EP-1) by the Commission. Time of use pricing will encourage far greater dependence on peaking and small intermediate coal plants by the utilities, since the relative uncertainty of time of use pricing means that utilities must continue to purchase all three sizes of plants. Load control reduces uncertainty and encourages a greater use of the very largest baseload plants.

As to the discouragement of solar and wind generated systems, in many jurisdictions just the opposite arguments are being made by environmentalists. They argue that time of use electricity pricing is necessary to provide inexpensive off-peak discounts as a backup for solar and wind systems. The Commission finds these environmentalist arguments to be sound and has started a generic case (05-EI-1) to pursue the promotion of a renewable energy systems objective.

As for the encouragement of electric resistance heating, the Commission is concerned about any dramatic increase in its use. The case just mentioned (05-EI-1) will address this potential problem and consider regulations to keep it from occurring. Furthermore, since off-peak prices include the full marginal operating costs of the off-peak sales under time of use pricing in general, and under 6630-ER-2/5 in particular, any fear that such sales are being priced below costs to all electric heating customers in the case at hand is unfounded.