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REPORT BY THE

Comptroller General

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Electric Utility Fuel-Procurement Practices And The Impact Of Rate Reform Activities On Small Businesses

Increased fuel costs have been a primary factor in the rapid rise in electric power costs. State commissions are reviewing utilities' fuel-procurement practices but more needs to be done to insure that the costs incurred are reasonable.

Electric rates for small commercial customers are generally higher than for other users. Changes in the present electric rate structure are being proposed or implemented in an attempt to reduce power consumption and costs. These changes, however, have been primarily directed at residential and industrial users. Few commercial customers choose these revised rates even when offered on a voluntary basis.

The report describes several actions which the Subcommittee on Minority Enterprise and General Oversight, House Committee on Small Business, may wish to encourage State regulatory commissions to pursue.

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EMD-79-2
JANUARY 19, 1979

B-178205

The Honorable
Chairman, Subcommittee on Minority
Enterprise and General Oversight
Committee on Small Business
House of Representatives

Dear Mr. Chairman:

As requested in a May 4, 1978, letter from former Chairman Joseph P. Addabbo, this report discusses State utility commission oversight activities with respect to electric utility fuel-procurement practices, the use of utility-owned coal mines, and the impact of various rate structures on small business electric rates.

As arranged with your office, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of the report. At that time we will send copies to interested parties and make copies available to others upon request.

Sincerely yours,

Elmer B. Staats

Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE SUBCOMMITTEE ON MINORITY ENTERPRISE AND GENERAL OVERSIGHT

ELECTRIC UTILITY FUEL-PROCUREMENT PRACTICES AND THE IMPACT OF RATE REFORM ACTIVITIES ON SMALL BUSINESSES

D I G E S T

Fuel costs are a major portion of a utility's total expenses. State regulatory commissions are concerned with rising fuel costs and with utilities' fuel-procurement practices. However, some State commissions do not periodically perform full-scale audits of these practices. Furthermore, auditing of such practices is difficult because State commissions generally have not established specific fuel-procurement policies for utilities to follow. (See pp. 5 to 10.)

The use of coal from utility-owned mines (captive coal) is increasing and concern is is being expressed in the Congress and some State utility commissions about the potential for inflated captive coal costs being passed on to consumers. State commissions that have captive coal operations need to periodically audit prices charged for captive coal to insure the reasonableness of the prices.

Utility companies are expected to expand their ownership of coal reserves and production. It appears, however, that this increase in utility-owned coal properties will not adversely affect the ownership or operations of the numerous small coal mines. (See pp. 10 to 15.)

Commercial customers, as a class, and small commercial customers in particular, generally pay a higher rate for power than either residential or industrial users. Some State commission and utility officials claim these customers cause much of the demand for higher-priced peak power. However, few studies have been done in this area to confirm whether or not this is true.

EMD-79-2

Revisions to the declining block method of structuring electric rates are being made but the small commercial users are not being considered. State commissions and electric utilities need to develop better data on power usage patterns of small commercial users and include these users in rate reform demonstration projects. (See pp. 18 to 29.)

MORE STATE OVERSIGHT OF UTILITY FUEL-PROCUREMENT PRACTICES IS NEEDED

GAO reviewed electric utilities in Michigan, New York, Pennsylvania, and Wisconsin and found that utilities in these states usually attempt to satisfy most of their fuel requirements through negotiated long-term contracts. Bids are initiallly solicited from a number of approved suppliers who are qualified to deliver the quality and quantity of coal needed. A price is determined after evaluating product quality, vendor reliability, and transportation costs.

Coal contracts, whether they be competitive or negotiated, do not set a price that is fixed for the length of the contract. They usually contain escalation or renegotiation clauses that allow the coal supplier's cost increases to be passed on to the utility. At one utility company, over a 10-year period, base prices of four major coal contracts increased on an average of 11 to 46 percent annually.

Reliable fuel supplies are not always assured under either competitive or negotiated contracts. Two utilities had experienced delivery shortages of about 50 percent of contract requirements because of too few railcars. Utilities generally make up these shortages by buying coal on the spot market, where prices are often higher. (See pp. 6 to 9.)

The nationwide use of utility-owned coal mines is expected to grow. In 1975, 27 utilities met 11.2 percent of their coal requirements from their own mines. Production from these mines is expected to triple by 1985 and will approach 19 percent of the utility industry's projected fuel requirements.

Michigan and Pennsylvania were the only States visited that had utility-owned coal mines. Michigan State officials have expressed concern about coal-pricing practices and regulatory commissions allowing coal reserve investments to be included in a utility's rate base. One of the major findings of a Pennsylvania commission audit report of a utility with captive-coal operations was that abnormal (unreasonable or non-competitive) production costs were being incurred by the utility and the recommendation was made that these costs should not be passed on to consumers. The Pennsylvania commission is developing guidelines which will define the production costs that can be included in the price charged for captive coal.

Small coal mines producing 100,000 tons or less per year are concentrated east of the Mississippi River and comprise 83 percent of all United States mines, but provide only 19 percent of total production. It does not appear that electric utilities are purchasing small coal mines and reducing the number of these operations. Federal Energy Regulatory Commission data shows that the West appears to offer a greater potential for the development of future captive coal mines because Western coal reserves are largely undeveloped and are well suited for large strip mining operations. The extent of western coal reserve development, however, will be influenced by environmental standards imposed on the industry. (See pp. 10 to 15.)

Pennsylvania was the only State visited that had specific fuel-procurement regulations and periodically performs full-scale audits of utilities' fuel purchasing practices. Improved audits of utilities fuel procurement practices are needed to insure that (1) fuel cost increases are reasonable, and (2) delivery shortages under long-term contracts are justified.

SMALL COMMMERCIAL CUSTOMERS GENERALLY PAY HIGHER ELECTRIC RATES THAN OTHER CUSTOMER CLASSES

Utility companies incur certain costs in providing electric power service to their customers. The revenues that are required to cover these costs are allocated to residential, commercial, and industrial customer classes by the utilities. The proposed revenue requirements and method of allocation is submitted for approval through the ratemaking process to the regulatory commission.

Commercial customers have generally been allocated a larger proportionate share of the utilities' total costs than either residential or industrial customers because utilities have generally claimed that they are responsible for high-cost peak-demand periods. As a result, the small commercial customer is

--bearing a greater share of the utilities' total cost of providing power than other users, and

--paying more per unit of power consumed than the large commercial user. (See pp. 18 to 20.)

RATE STRUCTURE REFORMS HAVE LITTLE IMPACT ON SMALL BUSINESS ENERGY COSTS

On the basis of the cost of providing electric service, utilities apply different rate structures to customers utilizing these services. Utilities historically have used the declining block rate to collect the necessary revenue. This rate rewards consumption by reducing the cost per unit as usage increases.

Increased fuel and construction costs have resulted in higher costs to consumers. To conserve fuel and reduce electric costs, State commissions are encouraging, and in some cases requiring, utilities to use other rate structures to recover their costs. These rate reforms use several pricing methods, such as adjusting rates according to the time of day electricity is used, reducing rates for the right to curtail customer service if necessary to meet peak loads, charging a flat rate regardless of usage levels, and increasing prices as consumption increases.

Some State commissions have required certain of their jurisdictional utilities to revise rate structures to reduce electric power consumption and rates for specified customers--usually residential or industrial users. In other cases, utilities have received State commission approval to offer these revised rate structures to customers on a voluntary basis.

The small commercial customer usually has been excluded from mandatory rate revision other than for flat rates. A few utilities have offered, or are experimenting with, voluntary time-of-day and interruptible rate structures for small commercial customers but acceptance to date has been minimal.

Several experiments and demonstration studies incorporating revised rate structures have been sponsored by the Federal government and the utility industry. Small commercial customers have generally not been included in these studies. Consequently, the effects of these revised rate structures on small commercial customers is not well known. (See pp. 18 to 29.)

OBSERVATIONS AND MATTERS FOR CONSIDERATION

GAO recognizes that the problems discussed in this report are matters for action by State commissions and, as such, are presently beyond Federal jurisdiction. Nevertheless, GAO believes the information in this report points out the need for State commissions to

--establish specific fuel-procurement policies and specific captive coal mine transfer pricing guidelines for electric utility companies to insure that fuel prices are reasonable and delivery shortages are justified,

--establish definitive guidelines for auditing utility fuel-procurement practices,

--conduct a more critical examination of utilities' cost-of-service studies to assess the validity of claims that commercial customers cause the higher-cost peak demands on the system, and

--conduct rate reform impact studies to consider the effect revised rate structures will have on small commercial customers. (See pp. 15 to 17 and 29.)

For this reason, GAO suggests that the subcommittee furnish copies of this report to all State commissions, together with other information developed during hearings on these matters.

AGENCY COMMENTS

State commissions' comments varied depending on the circumstances in their particular jurisdiction but generally reflected the belief that some of the generalizations in the report did not accurately portray the conditions in their State. In particular, two commissions expressed strong disagreement regarding the need for periodic full-scale audits of fuel-procurement practices and believe their monitoring and auditing activities are effective in assuring reasonable costs. While these ongoing monitoring activities and other technical comments have been recognized in the report, GAO continues to believe that periodic full-scale audits of fuel-procurement practices provide greater assurance of the reasonableness of utility fuel costs. (See pp. 17, 29 and 30).

C o n t e n t s

ABBREVIATIONS

DOE	Department of Energy
FEA	Federal Energy Administration
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GAO	General Accounting Office
kW	Kilowatts
kWh	Kilowatt hours
NARUC	National Association of Regulatory Utility Commissioners
PP&L	Pennsylvania Power & Light
TOD	Time-of-day

CHAPTER 1

INTRODUCTION

Until recently, there has been little demand for electric utility rate reform. Consumers and electric utilities alike have benefited from relatively inexpensive electric power. Within the past several years, however, the costs of primary fuels, construction costs of new generating facilities, as well as other utility costs, have risen sharply, forcing the average electricity prices paid by consumers to rise over 60 percent between 1970 and 1975.

A primary cause of the rapid rise in the price of electricity has been the dramatic increase in the price of fuels used by electric utilities. Between 1970 and 1975, fuel expenses, as a percentage of total expenses of utilities, rose from about 25 to 41 percent. This rapid escalation of fuel costs in recent years has led to increased concern about utilities' fuel-procurement practices.

RATE STRUCTURE REFORM

High electric rates have resulted in Federal, State, and utility initiatives to revise or consider revising rate structures to contain electric rate increases. In doing this they hope to encourage conservation and stabilize consumer demand. The Federal Energy Administration (FEA) 1/ has funded a number of demonstration projects to determine the effects of specific rate structure changes and identify ways for utilities to better manage their electric power load requirement. Most of this experimentation has been directed at residential and industrial customers with heavy emphasis on time-of-day rates for residential customers under which rates vary during peak and offpeak periods of usage. FEA issued a report which provided background on the projects and a largely qualitative assessment of the major issues affecting electricity generation and consumption but made no recommendations on the use of these rate structure changes.

A November 1977 report to the National Association of Regulatory Utility Commissioners (NARUC) covered

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1/FEA was incorporated into the Department of Energy on October 1, 1977.

--the technology and cost of time-of-day metering and electronic methods of controlling peak-period usage of electricity, and

--the feasibility and cost of shifting various types of usage from peak to offpeak periods.

Rate reform at the State level has been aimed at gradually phasing out block rate structures which provide incremental discounts for successive blocks of electricity consumption. Declining block rates are being replaced with rate structures which provide an incentive for more efficient use of electricity.

Under the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 note), State commissions are required, within 3 years of enactment, to consider putting six ratemaking standards into effect for regulated utilities. Among these standards are time-of-day rates, seasonal rates, cost-of-service pricing, interruptible rates, load management techniques, and a prohibition on declining block rates unless justified by costs.

ELECTRIC UTILITY RATEMAKING PROCESS AND JURISDICTIONAL RESPONSIBILITIES

The traditional ratemaking process has three major steps:

--Calculating the utility's revenue requirement which represents the utility's total cost of providing electric service to all customers, plus a profit margin.

--Allocating the revenue requirement to the customer classes responsible for the incurrence of these costs.

--Applying an appropriate rate structure which determines how the required revenue will be collected from customers.

The responsibility for managing the ratemaking process is divided between the Federal and the States' regulatory commissions. All electric power sold in the wholesale market is regulated at the Federal level by the Federal Energy Regulatory Commission (FERC) which accepts utilities' rate filings, holds rate hearings, and issues final orders on rate applications. These transactions consist of sales between utilities and constitute the bulk power market. About 8 to 10 percent of total electric power sales are made in this bulk power market.

The remaining 90 percent of the power produced is sold to end users in the retail market. These intrastate sales are regulated by State public utility commissions, and they function in a manner similar to that of FERC. Although the initial cost of bulk power set by FERC is a contributing factor in the retail prices charged by some utilities, State regulatory commission policies and practices have a much greater influence on customer charges. The extent to which each commission establishes policies and guidelines for its jurisdictional utilities' operations and the scrutiny given to utilities' proposed rate increases will directly affect the power costs to consumers.

REPORT OBJECTIVES

The Subcommittee on Minority Enterprise and General Oversight, House Committee on Small Business, has been concerned about small business electricity prices. Its initial concern was expressed in an October 1977 letter to us which requested that we examine the impact of high energy costs on small business operations. A letter report on our work in Michigan, New York, and Pennsylvania was issued to the subcommittee chairman on February 6, 1978 (EMD-78-33), and we subsequently participated in a hearing held jointly by the Subcommittees on Minority Enterprise and General Oversight, and on Energy, Environment, Safety, and Research.

As a result of additional questions raised during the hearing, the Chairman of the Subcommittee on Minority Enterprise and General Oversight requested that we followup on our earlier work by analyzing, in a four State area,

--electric utility fuel procurement practices allowed by State public utility commissions,

--State review of fuel procurements,

--the use of captive coal mines (mines owned or controlled by electric utilities), and

--the impact of current and proposed rate structures on small business electric rates.

SCOPE OF REVIEW

During the course of our review we visited public utility commissions in Michigan, New York, Pennsylvania and Wisconsin and 11 utility companies accounting for about 67 percent of the total electric sales in the four States during 1976. We discussed the impact of electric utility fuel-procurement practices and rate reform on small businesses with State and utility officials. In addition, we reviewed various Federal and State rate schedules, orders and opinions, and reports and studies regarding electric utility fuel procurements and rate structure reform.

In responding to the specific items in the Chairman's request, we noted several additional factors that appeared to impact on the fuel procurement and ratemaking issues. Among these factors are the apparent lack of State monitoring of coal contract price increase provisions after the contract is awarded, the general lack of intervention in rate cases by small commercial customers, and the allocation of utility costs to the various customer classes. We did not have sufficient time to expand our review and do an in-depth analysis of these factors and their affect on small businesses; however, we have included them to some extent because we believe they should be brought to the attention of the subcommittee.

CHAPTER 2

ELECTRIC UTILITY FUEL-PROCUREMENT PRACTICES AND STATE OVERSIGHT

Rising fuel costs and the use of automatic fuel adjustment clauses have emphasized the need for State reviews of electric utility fuel-procurement practices. Most fuel contracts contain escalation clauses that allow significant increases in fuel costs after the contract is initially awarded. Although the State commissions we visited were monitoring electric utility fuel-procurement practices to some extent, we believe that full-scale audits extending to fuel suppliers, if necesary, would provide more assurance of the reasonableness of utility fuel costs.

The use of captive coal for meeting electric utilities' fuel requirements is growing substantially. Concern is being expressed in the Congress and some State utility commissions over the potential for inflating captive coal costs and whether the current State regulation of prices charged for captive coal is effective in preventing such an occurrence.

Electric utility companies incur a number of costs in providing reliable service to consumers. Expenditures for such items as fuel, labor, equipment, administrative support, interest on borrowed money, and dividend payments need to be recovered by the utilities. An examination of these expenditures and a determination as to their reasonableness is the first step in a regulatory commission's ratemaking process.

Fuel costs account for about 40 percent of a utility's total expenses. Because of the significance of this expense item, fluctuations in fuel prices can greatly affect a utility's revenue requirements. During periods of rapidly rising fuel prices, utilities need quick approval from the regulatory commissions to recover the additional fuel costs. To assist the utility companies, State commissions have generally approved an automatic fuel adjustment clause in their rate approvals. This clause usually allows the utilities to adjust their charges to customers on a periodic basis to account for fuel cost charges without submitting a formal request to the regulatory commissions for a rate hearing on each price change.

Electric utilities in the four States we reviewed use long-term contracts to satisfy most of their fuel requirements.

The contract terms are generally negotiated after receiving bids from several suppliers.

ELECTRIC UTILITY FUEL-PROCUREMENT PRACTICES

Most electric utilities in Michigan, New York, and Pennsylvania buy fuel under negotiated contracts. 1/ The usual procedure of utilities in these States is to solicit bids from several suppliers. The bids are evaluated for price, quality of product, vendor reliability, and transportation costs. Further price negotiations generally follow. The majority of utilities reviewed meets its fuel requirements by contracting with more than one supplier because it believes that multiple sources assure reliability of supply. We have since found that Wisconsin utilities buy their fuel in essentially the same manner as utilities in the three other States.

Officials of two major Wisconsin utilities said they were in the process of drafting fuel-procurement guidelines. These draft guidelines, however, were not available for our review. According to the officials, their current fuel-procurement practice is to solicit bids from suppliers and award the contract to one of the qualified bidders. Wisconsin Electric Power Co., for example, may select a supplier from three to eight qualified bidders and then negotiate the final price on the basis of quality, reliability of delivery, and geographic location. The utility official would not provide any details covering the negotiation process.

Coal contracts usually contain escalation or renegotiation clauses that allow a coal supplier's cost increases to be passed on to the utility. We were provided with limited information on four major coal contracts of one Wisconsin utility which showed that base prices increased on an average of 11 to 46 percent annually under numerous cost escalators as illustrated below:

1/Letter report (EMD-78-33, February 6, 1978) to the Chairman, Subcommittee on Minority Enterprise and General Oversight, House Committee on Small Business.

Date of Contract	No. of Cost Escalators	No. of Changes	Price Original	Price Current	Date of last change	Average Annual Increase
5-22-67	18	69	$5.50	$11.86	11-1-77	11%
5-26-67	16	45	3.85	12.28	7-1-77	22
5-29-67	Unknown	161	4.00	21.34	1-1-78	46
8-24-72	18	46	4.49	8.53	1-1-78	17

According to one commission staff member, the high number of cost escalators assures coal delivery and the recovery of all coal supplier costs. One new cost escalator allows coal suppliers to open up negotiations for new prices every 3 years. In addition, certain contract provisions, particularly the renegotiation of prices every 3 years, are of monetary benefit to coal suppliers and eliminate many future uncertainties for both the utility and the coal supplier.

A similar situation exists in Michigan. A 1976 Michigan State House Committee report found that in one utility

> "* * * almost every major coal contract had been renegotiated or had cost escalation clauses changed to the benefit of the coal supplier in the last five years * * *"

We believe that such contract provisions place an unfair burden on utilities because much of the cost risks are borne by the electric utilities and very little by coal suppliers.

In addition to potentially higher fuel costs from escalator and renegotation clauses, a utility also can have delivery problems which may increase fuel costs. Although utility officials are concerned about fuel prices, they told us that in some cases other factors, such as delivery reliability, may assume greater importance than just obtaining the lowest possible price. Concern over such non-price factors is often used to support the negotiated procurement process. Reliable fuel supplies, however, are not always assured under either competitive or negotiated long-term contracts. Two Pennsylvania utilities were experiencing shortages in coal deliveries under long-term contracts that amounted to about 50 percent. The utilities generally made up these shortages by purchasing coal on the spot market where prices are often higher.

Even though the contracts contained replacement clauses that require suppliers to make up the delivery shortages, the contracts also contained "force majeure" clauses under which shortages are excused if they are beyond the control of the supplier. According to utility officials, most of the shortages were caused by the lack of railroad cars; therefore, the coal supplier did not have to make up the shortage.

A Federal Railroad Administration official confirmed that generally the railroad industry on the east coast had experienced both railroad car and locomotive shortages.

STATE REVIEW OF ELECTRIC UTILITY FUEL-PROCUREMENT ACTIVITIES

The House Subcommittee on Minority Enterprise and General Oversight requested nationwide information on the number of State commissions that require electric utilities to use competitive fuel procurement practices and the extent to which the four State commissions are monitoring electric utility company compliance.

A recently issued NARUC report 1/ stated that only two State commissions require electric utilities to solicit sealed bids before awarding contracts. The report pointed out, however, that many electric utilities consider negotiated contracts to be a more effective fuel purchasing method than formal competitive contracts. None of the State commissions we visited, however, required utitilies to solicit sealed bids for fuel procurement. The State commissions in Michigan, New York, and Wisconsin have general procurement regulations covering services, equipment and materials. These general regulations require the utility to document the procedures used in awarding the contract. The Pennsylvania commission, however, had issued specific fuel-procurement regulations with criteria to evaluate fuel purchases. Pennsylvania's regulations not only specify that the electric utility document its fuel procurement contract procedures, but specify how such items as total fuel costs, including transportation, are to be recorded and what documentation is necessary to support future changes in fuel costs under escalation clauses. The regulations are aimed at providing the commission with information that will facilitate audits to prevent unreasonable costs from being passed on to customers.

1/ State Commission Regulation and Monitoring of the Fuel Adjustment Clause, Purchased Gas Adjustment Clause and Electric and Gas Utility Fuel-Procurement Practices, dated October 27, 1978.

The NARUC report provided nationwide information on State commission efforts to monitor electric utility fuel-procurement practices. The report disclosed that 40 State commissions audit electric utility fuel procurement practices to some degree. It pointed out, however, that the type, frequency, and extent of monitoring fuel-procurement practices varies by State due to differences in the operating characteristics and environment of regulated firms, statutory authority (i.e., State commission jurisdiction), budget considerations, work load, and other pertinent factors. While many State commission audits concentrate on such areas as vendor selection, contract terms and conditions, and/or fuel invoices, other State commission audits cover all aspects of fuel-procurement policies and practices. The Pennsylvania commission was the only State we visited that periodically audits all aspects of its utilities' fuel-procurement practices. The other three State commissions--Michigan, New York, and Wisconsin--have thus far opted to audit electric utility fuel-procurement practices by means other than the full-scale audit approach. Details on the audit procedures in the four States we visited are discussed below.

According to a New York commission official, the commission should become more involved in fuel-procurement reviews. Currently, the only review that occurs is during fuel adjustment clause proceedings. However, the New York commission completed an audit of its utilities' fuel-procurement practices in August 1978 and submitted it as an exhibit in a generic fuel adjustment case. The commission is trying to determine how to regulate fuel-purchasing practices more effectively--possibly through periodic fuel-procurement audits as recommended in its generic fuel adjustment case.

As stated in our February 1978 report, the Michigan commission's 1976 staff study of utility companies' procurement practices found that improved audits and additional management incentives were needed to help keep the cost of fuel down. Although the Michigan commission does not perform a full-scale audit of utilities' fuel-procurement practices, it has taken several steps over the past 2 years to more effectively scrutinize electric utility fuel-procurement practices including reviews of fuel contracts, fuel contract renegotiations and captive coal mine costs. The commission also has the option of initiating a full-scale audit if major problems are uncovered during its informal reviews. To date, no such audits have been initiated. The Michigan commission does not believe that full-scale audits are cost-effective at this time and that its informal approach is best suited to its particular needs.

Although the Wisconsin commission does not routinely perform full-scale audits of utilities' fuel-procurement practices, the commission believes that its audits of fuel costs during rate cases, reviews of coal contract price escalation and renegotiation provisions, the full-scale audits on an as-needed basis are effective in assuring reasonable fuel costs.

The Pennsylvania Public Utility Commission periodically audits all aspects of electric utility fuel procurement practices. During our prior review, the Pennsylvania commission was performing audits of three utilities we visited. As of August 23, 1978, the commission had issued only one final audit report. The major report finding was that abnormal (unreasonable or non-competitive) captive coal production costs were being incurred by the utility company and the recommendation was made that these costs should not be passed on to consumers as an automatic fuel adjustment. As a result of this audit, the commission is planning to develop captive coal mine guidelines which will define the production costs that can be included in the price charged for captive coal.

Another method for State commissions to assure themselves that cost increases under long-term fuel contracts are reasonable is to audit coal supplier records. None of the State commissions we visited audit utilities' nonaffiliated fuel suppliers to assure themselves of the reasonableness of cost increases being passed on to the utility under escalation clauses. The Pennsylvania commission's audit division however, believes it needs, and plans to seek, authority from the State legislature to audit both affiliated and nonaffiliated fuel suppliers.

ELECTRIC UTILITY CAPTIVE COAL OPERATIONS

To better insure their coal supplies, many electric utilities have been relying heavily on long-term contracts. A growing number of utilities, however, have purchased or gained control of coal operations for their own needs (captive coal). Electric utility captive coal mines may be either part of the utility operation or be a subsidiary operation. Most of the captive coal operations have been formed as subsidiaries separate from the parent company.

A Federal Power Commission (FPC) 1/ report 2/ shows that 13.4 million tons, or about 5.5 percent of all coal

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1/FERC replaced FPC on October 1, 1977.

2/FPC report entitled "Electric Utilities Captive Coal Operations," issued in June 1977.

used by electric utilities came from captive mines in 1965. By 1975, utilities' use of captive coal had increased to 48.4 million tons, or about 11.2 percent of coal used by utilities. The data also shows that by the end of 1975, 27 utilities were supplying all or part of their coal requirements with captive coal. Production from these mines is expected to triple by 1985 and will approach 19 percent of the utility industry's projected fuel requirements.

Regional trends and the future of captive coal operations

Significant regional differences exist in captive coal mine ownership patterns. The number of utilities with a mixed supply (both captive coal and coal bought on the market) and an entire supply from captive coal in 1975 is shown below.

Regional Patterns in Captive Coal Mine Holdings

Type of supply	Number of Utilities: West of Miss. River	East of Miss. River	Total
Mixed	2	13	15
Entirely from captive mines	11	1	12
Total	13	14	27

Although captive coal mine ownership is about equal on a regional basis:

- --Eastern utilities tend to use a mixed supply.
- --Western utilities tend to depend almost entirely on their captive coal mines.
- --The West appears to offer the greater potential for the development of future captive coal mines because Western coal reserves are largely undeveloped.
- --Western coal is largely suited to strip mining.

Because strip mines are usually large operations and less expensive than underground mines, utilities find Western strip mines particularly attractive. Finally, due to the wide dispersion of Western coal reserves and attendent high transportation costs, utilities may find it attractive to build Western mine mouth plants which naturally involve captive coal mines to serve the generating plants. According to a 1976 FPC survey of electric utilities which control coal reserves, captive coal production is expected to triple during the period 1975 to 1985, expanding to 145 million tons per year. This will be about 18.8 percent of the utility industry's projected fuel requirements. The survey also discloses that most of the increased production will come from the 27 utilities that were operating captive mines in 1975, although 12 new utility companies also were planning coal production.

FERC data shows that the electric utility industry plans to add 260 new coal-fired generating units between 1977 and 1986. One indicator of future electric utility captive coal operations can be found in an analysis of coal suppliers under contract to supply coal for these new units. Of the 258.9 million tons of coal under contract to these new units as of October 1977, for delivery in 1986, 34.3 percent is anticipated to come from captive coal mine operations. Independent coal producers will supply 27 percent of the coal; the remaining 38.7 percent will be supplied from coal mines owned or controlled by oil companies.

Captive coal operations in the four States visited

Major electric utility companies in New York and Wisconsin are not involved in captive coal mine operations. At least four utilities in Pennsylvania and Michigan, however, own captive mines. Pennsylvania has two utility companies--Pennsylvania Power & Light Company (PP&L) and Duquesne Light Company--with captive coal operations. PP&L has five captive coal mines which provide about 50 percent of the utilities total coal needs. Our previous report emphasized the problems PP&L had with the high production costs at two of its mines and that these problems were being resolved with the Pennsylvania commission. The commission's audit of PP&L operations, which also pointed out the problems with the captive coal costs, stated that the use of such coal and the utility-owned rail transportation equipment have resulted in a stable supply of coal and a substantial reduction in transportation costs to PP&L and its customers.

The Duquesne Light Company has only one captive mine and it provides about 16 percent of the utility's coal requirements. According to a utility official, the company receives the coal at the cost of production. The company's 1977 annual report to FERC showed that this cost was about $29 per ton compared to a cost of about $22 per ton for all other coal purchased by that utility.

Two major utilities serving Michigan--Detroit Edison Company and the Indiana and Michigan Electric Company--have captive coal mines. The Michigan commission has started to scrutinize utilities' investments in coal properties more closely, particularly after a 1976 State House Committee Report disclosed that utilities' investments in nonregulated businesses were included in their rate bases contrary to generally accepted ratemaking policy. The Michigan commission does not audit electric utilities' affiliated fuel suppliers; however, costs incurred or charges made by a utility's subsidiary are not includable for purposes of the fuel cost adjustment unless specifically authorized by the commission.

Transfer pricing of captive coal

One of the concerns associated with captive coal mines is the potential for inflated coal costs being passed on to consumers via the automatic fuel adjustment provision. A May 1978 U.S. Department of Justice report entitled "Competition in the Coal Industry" expressed concern regarding the transfer price a utility pays for coal from its subsidiary coal company and the possibility of utility companies earning monopoly profits from these operations. The Justice Department plans to study this issue further to determine whether current regulations effectively prevent such anticompetitive effects and whether these anticompetitive dangers outweigh the benefits of utilities' backward integration.

State commissions allow several transfer pricing methods to be used for the sale of captive coal to the parent company, and unreasonably high coal costs may result if the transfer prices are not closely reviewed by State commissions. The three most commonly used methods are "market pricing," "cost-of-service pricing," and "cost-plus pricing."

Market pricing can be established in either of two ways:

--The transfer price can be related to coal prices paid by the utility for similar quality coal purchased on the open market.

--The transfer price can be related to the price received for coal produced by independent coal mines in the vicinity of the captive mine.

Under the first alternative, and assuming the full cost of the fuel can be passed on to the utility's customers, utilities would have less incentive to purchase coal on the open market at the lowest cost. The transfer price of the captive coal would thereby be pushed up, allowing the utility to increase its profits from the captive operations. Profits of the subsidiary are considered nonutility income for the parent utility and normally are not regulated by most States' utility commissions.

Under cost-of-service pricing, the transfer price is set at a level which will cover the anticipated production costs and a rate of return on the investment in the subsidiary. With cost-of-service pricing, the transfer price of the captive coal is regulated in the same manner in which the parent utility's cost of service is regulated. Therefore, if actual production costs are higher than anticipated, the rate of return will be smaller and vice versa. Under this pricing mechanism, coal pricing disputes are shifted to a consideration of the appropriate rate base and rate of return, and production efficiency is encouraged.

Cost-plus pricing relates the transfer price to all production costs plus a set rate of return. A major disadvantage of this method is the lack of incentive to make the captive mining process more efficient.

Shown below are the transfer pricing methods allowed by 12 State commissions that have jurisdictional utilities with captive coal operations. 1/

Transfer pricing method	Number of states using transfer pricing method
Market pricing	5
Cost-of-service pricing	4
Cost-plus pricing	3

Impact of captive coal mines on small mine operators

The Subcommittee on Minority Enterprise and General Oversight expressed concern regarding the impact that extensive electric utility captive coal operations would have on small coal mine operators.

1/FPC report entitled "Electric Utilities Captive Coal Operations" issued in June 1977.

We conclude that there is likely to be little impact. For the purpose of this report, small mines are defined as those producing 100,000 tons per year or less. Although these small mines comprise about 83 percent of the nearly 6200 coal mines in the United States, they supply only about 19 percent of the coal. The trend over the years has been for the larger producers to supply an increasing proportion of the coal.

Nearly all the small coal mines are located east of the Mississippi River in the Appalachian States. Furthermore, about 60 percent of the small coal mines are surface operations.

Small coal mine operators are generally of two types--intermittent and permanent. The intermittent producers engage in other businesses; e.g., construction, and only produce coal when spot market prices appear favorable. Frequently, these operators will have a short lease of about 5 years. Permanent operators are those whose main business is coal mining; e.g., family-owned coal mines of the Appalachian region.

FERC data on new coal-fired generating units shows that compared to the East, much more of the coal in the West will be produced by captive operations or oil industry controlled firms. FERC stated the major reason for captive coal operations is the limited development of the Western coal industry, the relatively small cost (compared to an underground mine) of developing a large strip mining operation, and the opportunity to build a minemouth plant thereby minimizing coal transportation costs.

Development of western coal reserves may be largely influenced, however, by environmental (clean air) standards yet to be finalized. In addition, about 66 percent of the electric utilities' recoverable reserves are already located west of the Mississippi River. It is therefore unlikely that electric utilities, which are planning captive coal operations, will impact very much on the small coal miners.

OBSERVATIONS AND MATTERS FOR CONSIDERATION

Rising fuel costs and the automatic passing on of these costs by utilities to their customers are receiving increased attention by State commissions. State commissions are beginning to concern themselves with utilities' fuel-procurement practices, but three of the four State commissions we visted do not periodically perform full-scale audits of these practices. Furthermore, auditing of such practices is difficult in these States because their regulations do not contain criteria for evaluating fuel purchases.

We believe that State commissions need to periodically audit utility fuel-procurement practices to insure that

--fuel cost increases are reasonable and

--delivery shortages under long-term contracts are justified.

Long-term coal contracts generally contain escalation and renegotiation clauses that allow the coal supplier to increase the price of coal after the contract is awarded. Although coal contracts often contain an audit clause under which the utility can review supplier data justifying these cost increases, the State commissions do not assure themselves of the reasonableness of such cost increases. Such assurances could be achieved by reviewing utility audits of their coal suppliers or by commission reviews of supplier's cost data. State commission authority to review supplier's cost data may require State legislative approval.

Substantial coal delivery shortages under long-term contracts are occurring in some cases. This tends to increase the cost of coal because utilities generally make up the shortages by purchasing spot market coal which is often higher priced. State commissions with jurisdictional utilities experiencing such shortfalls need to assure themselves that such shortages are justified. Two utilities in one of the States visited indicated they were experiencing substantial delivery shortfalls, but the limited timeframe of our review did not allow us to determine how widespread this may be in other States.

Electric utilities' use of captive coal is growing and questions are being raised as to whether current transfer pricing regulations are effective in preventing excessive costs being passed on to consumers. We believe that where it is not already being done, State commissions that have electric utilites with captive coal operations should periodically audit transfer prices to insure the reasonableness of the prices.

We recognize that the problems discussed in this report are matters for action by State commissions and as such are presently beyond Federal jurisdiction. However, the Subcommittee may wish to inform State commissions of its concerns over increasing electric energy costs and, where appropriate, encourage them to

--establish specific fuel-procurement policies and specific captive coal mine transfer pricing guidelines for electric utility companies to insure that fuel prices are reasonable and delivery shortages are justified, and

--establish definitive guidelines for auditing utility fuel-procurement practices.

STATE COMMISSION COMMENTS

We provided extracts of our proposed report to the four State commissions named in this report to obtain their comments. All four State commission responded, three in writing and one orally. The written comments and the oral comments from the Wisconsin commission generally reflected the belief that some of the report's generalizations did not accurately portray conditions in their State. In particular, the Michigan and Wisconsin commissions expressed strong disagreement regarding the need for periodic full-scale audits of fuel-procurement practices and believe their monitoring and auditing activities are effective in assuring reasonable fuel costs. The New York commission pointed out that they have conducted one audit of utilities' fuel-procurement practices and it has been recommended that such audits be done on a periodic basis. The Pennsylvania commission generally concurred with our report but pointed out that their commission staff is already conducting periodic full-scale audits of fuel-procurement practices and periodically reviews the reasonableness of coal transfer prices.

While these ongoing monitoring activities and other technical comments have been recognized in the report, we continue to believe that periodic full-scale audits of fuel-procurement practices provide greater assurance of the reasonableness of utility fuel costs. The full text of the State commissions' written comments are included as appendices to this report.

CHAPTER 3

UTILITIES' COST ALLOCATION PROCESS

AND RATE STRUCTURE REFORMS

A major element in the second step of the ratemaking process is a study of the cost of service associated with providing electricity to each customer class--residential, commercial, and industrial. Although these costs vary depending on customer demands and usage, utilities allocate a larger proportionate share of these costs to commercial customers because it is claimed that they are responsible for the high peak demand which requires the utility to incur additional costs.

On the basis of the cost of electric service, utilities apply different rate structures to recover their costs and achieve a fair rate of return. Although rate structures should reflect the cost of providing service, the rates historically have promoted consumption and growth. Increasing fuel and construction costs, however, have encouraged rate reform initiatives to promote energy conservation and reduce electric costs to consumers.

In the four States we visited, State commissions are taking the initiative and encouraging utilities to reform rate structures. These rate reforms--mandatory and voluntary--are giving certain classes of utility company customers opportunities to reduce consumption and thereby reduce their electric costs. The reform has been gradual and primarily aimed at the large number of residential customers and high-energy use industrial customers. Rate reform has had little effect on small commercial customers because the revised rate structures used by utilities are not generally mandatory for them.

The larger proportionate share of the utilities' costs allocated to commercial customers results in higher electric rates than applied to other customers. Rate reform studies, designed to demonstrate how electric power consumption and rates can be reduced, however, have been directed primarily at residential and industrial customers to the exclusion of small commercial customers.

COMMERCIAL CUSTOMERS AND THE COST ALLOCATION PROCESS

During the second ratemaking step the utility determines how its total revenue requirement is allocated to each of its customer classes--generally residential, commercial, and industrial. To arrive at these amounts the utility divides the total cost of providing electric service into variable costs (those costs that vary on the basis of consumption) and fixed costs. The utility studies these costs and then prorates them to each customer class.

Because a utility company can reasonably project the power consumption of a customer class, it can allocate variable costs without great difficulty.

However, a utility finds allocating fixed capital costs for generation equipment and for transmission and distribution facilities more difficult. These capacity costs are largely joint costs in that the facilities are required to generate and transmit power to all customer classes. The allocation of joint costs to the customer classes is particularly judgemental; therefore, the possibility exists that a utility will allocate unfair portions of these costs to some customer classes.

Some regulatory and utility officials told us that commercial customers, as a class, have generally been allocated a larger proportionate share of the utilities total costs than either residential or industrial customers. Thus commercial customers have paid a higher per-unit cost for power since they must contribute a larger share of the total revenue requirements of the utility.

Some State commission and utility officials told us that the reason small commercial customers pay higher rates than other customers is because they create a high peak demand during daytime operations, requiring utilities to use higher-cost generating units. Consequently, the commercial customer class is allocated a proportionately larger share of the joint costs and pays higher per unit costs than other customer classes. However, because few rate-design studies on commercial customers have been done in this area, the validity of these statements are open to question. For example, according to a Wisconsin commission official, all customer classes contribute to the high daytime peak demand; therefore, the high generating costs should be shared equally by all customers.

Another reason for higher commercial rates advanced by a State commission official is that these customers, as a class, have not effectively intervened during the rate hearing process when the utilities' allocated revenue requirements are reviewed.

Although we did not have sufficient time to review the intervention issue in detail, we did note that while residential and industrial customers are usually represented at rate hearings, commercial customers, and in particular the smaller businesses, are not. The inequities that appear to exist in rate hearing interventions have been noted in the recently enacted energy legislation.

The Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 note) contains a provision which will allow greater consumer representation in regulatory proceedings. It provides a means by which consumers can intervene and be compensated by the utility if it is found that the utility has not complied with major provisions of the utility rate reform section such as minimum electric ratemaking standards designed to reflect the cost of providing electric service to consumers and encourage conservation.

Small commercial customers, whose electric rates are disproportionately high, will therefore have the opportunity to challenge the method of allocating costs.

REVISED AND PROPOSED RATE STRUCTURES

The third step in the ratemaking process is the selection of a rate structure. This step allows the utility to recover the revenue requirements determined during the second ratemaking step, in which costs are allocated to the various customer classes.

Total rate structure describes how the revenue level is collected from customers and includes both rate form and level. Examples of rate form include declining block, time-of-day (TOD), flat, and inverted. Rate level refers to the cost per kilowatt hour (kWh) in a specific rate form.

The declining block rate structure has been the predominant method used by electric utilities to recover their costs from consumers. Major cost benefits have gone to the large users in each customer class because declining block rates price successive blocks of kWh usage at lower per-unit prices. High energy consumption is rewarded with lower block unit prices, and such rates do not provide an incentive for efficient use of electricity.

Rate reform activity has increased in recent years in an attempt to conserve energy and contain electricity prices. Although declining block rates are still widely used, all four States are questioning the use of these rates and electric utilities are increasing the use of TOD, interruptible, flat, and inverted rate structures as described below.

--TOD rates provide for the price per kWh to vary during peak and offpeak periods.

--Interruptible rates provide lower prices per kWh to customers who agree to have their electric service curtailed during peak periods.

--Flat rates provide a uniform price per kWh regardless of usage.

--Inverted rates provide for the price per kWh to increase as electric power usage increases.

These reforms in rate structures are generally aimed at the large number of residential customers and high energy use industrial customers. The small commercial class of customers, which is the smallest in electric usage, has not been materially affected by these rate reforms.

One proposed rate structure, however, has been aimed specifically at the small commercial customer. The Consolidated Edison Company of New York, Inc. (Con Edison) proposed an area development rate in May 1978 that would provide a reduction in rates for small, energy-intensive industries to induce them to remain in New York. The proposed rate is still under State commission consideration.

The credit would be a maximum of $5 per kilowatt (kW), or about one half of the demand charge paid by most businesses. Con Edison stated that because more than 40 percent of the electric bills of most manufacturing and processing businesses constitute demand charges, businesses eligible for the area development credit could see their bills go down by as much as 20 percent in the first year--if the credit is approved by the New York commission.

Based on information filed by Con Edison, the New York commission believes that the rate is discriminatory because it offers a discount from the cost of service to a particular class of customers, and not to all customers. The State commission is reserving judgement, however, because it does not believe sufficient information has been filed to justify the rate.

A discussion of each of the four major rate revisions and their use by utility companies in the four States follows.

Time-of-day rates

TOD rates provide for the pricing of electricity as a function of time; i.e., higher prices during onpeak higher-cost periods and lower prices during offpeak periods when production costs are less. Consequently, customers who are able to shift their electric usage to offpeak periods have the opportunity of reducing their electric bills. The acceptance of TOD rates will depend on several factors including metering costs, onpeak/offpeak rate differentials, and the length of the onpeak/offpeak periods.

Eight of the eleven utilities we visited in the four States had TOD rates, but they generally applied to only their largest customers. Three of the utilities had voluntary TOD rates and five utilities required their use--two for industrial customers only, two for both industrial and large commercial customers, and one utility requires TOD rates for large commercial and industrial users plus a few residential customers.

The utilities that offered voluntary TOD rates did not have large percentages of customers on these rates. For example, one Pennsylvania utility offered voluntary TOD rates to all commercial customers, but no small commercial customers had accepted and only eight large commercial customers had accepted. A utility official told us, however, that they plan to promote TOD rates with greater rate differentials. Another Pennsylvania utility offered voluntary rates to some of its large commercial and industrial customers but only about 8.7 percent of the customers are using this rate. One of the largest Michigan utilities also offered TOD rates to its large commercial and industrial customers on a voluntary basis and over 1600 qualified users have accepted the offer.

In addition to the ongoing voluntary programs for TOD rates, two Michigan utilities and one New York utility are experimenting with voluntary TOD rates for a limited number of residential and commercial customers. One of the Michigan utilities includes only residential customers in its program. The other Michigan utility has 100 residential and 100 commercial customers on TOD rates. The New York utility plans to start its program in October 1978 with 600 each of residential and commercial customers. At the time of our visit in June 1978, 438 residential customers had volunteered to participate but only 6 commercial customers had agreed to use TOD rates.

Five of the utilities we visited have mandatory TOD rates for some of their customers--two in Wisconsin and one each in Michigan, New York, and Pennsylvania. Both Wisconsin utilities require TOD rates for their large commercial and industrial customers and one of them also has about 500 residential customers on mandatory TOD rates. This utility plans to extend these rates to additional residential customers in 1979. The New York and Pennsylvania utilities apply TOD rates to their largest commercial and industrial customers while the Michigan utility includes only its large industrial customers.

TOD rates have not always been accepted by large customers. For example, New York's Long Island Lighting Company (LILCO) has had problems with its approximately 200 TOD customers. The rate differential for onpeak to offpeak is about four to one. We were advised by LILCO officials that because TOD rates have increased the electric-power costs of these customers, the Retail Merchants Association has successfully challenged these rates in a court suit 1/ claiming the rate is discriminatory because it only applies to large customers. Both LILCO and the New York commission are appealing the court decision. They claim that the decision will be detrimental to some of the customers because TOD rates will be replaced with seasonal rates containing a minimum monthly charge for energy or demand that is some specified fraction of the charge for the month of peak use. They claim that this will result in the customers paying higher electric bills than they would have paid under TOD rates.

Interruptible rates

Interruptible rates provide lower prices to customers who agree to have their electric service curtailed during peak periods. These rates provide utilities with the means to reduce peak demand and minimize the use of less efficient equipment thus reducing costs during peak periods.

Two types of voluntary interruptible service were offered by utilities. One type applies only to large users. Utilities in all four States offered this service to their large customers but generally limited it to those customers whose demand was 1,000 kWs or more. None of the utilities had more than one large customer on this service. Under this service customers can either be interrupted at any time the utility determines the need or they can only be interrupted during mutually agreed upon peak periods. Generally, the length and number of times service could be interrupted

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1/Court of Appeals of New York State, Case Number 62-AD-2nd-314.

were specified in the contract between the utility and the customer. This service provides utilities with the load management ability to reduce large amounts of demand with a minimum amount of administrative effort.

Another type of interruptible service was offered by several utilities to their residential and commercial customers. Two utilities each in Michigan and Wisconsin and one utility in Pennsylvania offered interruptible controlled water heating service to their residential customers. One Michigan utility we visited had about 40 percent of its eligible residential electric water heating load on this service. The utility also offered similar service to its commercial customers, but only 3,900 customers, or about 3 percent, were using this service as of June 1, 1978. A utility official told us that many commercial customers had no need for this service due to the nature of their businesses, or because they used natural gas for water heating.

A Wisconsin utility provided interruptible water heating service to about 4,000 residential customers, or less than one percent, of its total residential customers as of August 1978. The utility plans to provide this service to 150,000 residential customers within the next 5 to 7 years which will represent about 75 percent of all residential water heating customers. The utility also has offered interruptible water heating service to its commercial customers, but only 3,000 customers, or about 5 percent, used this service.

Flat rates

Flat rates provide a constant charge for electricity usage, regardless of the volume being used. Electric utilities can either design flat rates to provide uniform customer, energy, or demand charges for all customer classes (residential, commercial, and industrial) or provide a uniform charge within each customer class.

Three of the four State commissions have approved flat rates for certain customer classes of some utilities. Two major utilities in Michigan, Detroit Edison Company and Consumers Power Company, have used mandatory flat rates for their small commercial customers since 1974. As of September 29, 1978, mandatory flat rates are also being used by these utilities for all commercial and industrial customers.

Pennsylvania's commission had not approved flat rates, but is in favor of a "gradual" shift to flat rates for residential use. According to the commission's December 1977 report on its generic rate structure investigation, Pennsylvania utilities are tending toward a flat rate structure for residential customers by placing future rate increases on the last blocks of existing declining block rates and through the application of the fuel adjustment clause which further flattens these rates.

One New York and two Wisconsin utilities have mandatory flat rates for certain customer classes. For instance, New York's Niagara Mohawk Power Corporation utility implemented a mandatory flat rate for its residential customers in July 1978. According to a New York commission official, flat rates would have a greater cost impact on commercial and industrial customers than on residential customers because the large users receive a greater benefit from the declining block rate schedules.

The Wisconsin commission approved flat rates for Wisconsin Electric Power in a January 1978 order. This order authorized Wisconsin Electric Power to implement flat rates for its residential, commercial, and industrial customers. Commercial customers will still pay a higher rate, however, than either residential or industrial customers.

Inverted rates

Inverted rates are the inverse of declining block rates. The price per kWh, therefore, increases as usage increases. Michigan and Pennsylvania were the only States visited that have inverted rates. Michigan's two largest electric utilities have mandatory inverted rates which are applicable only to residential customers. The Michigan commission is not considering inverted rates for commercial or industrial customers at this time. One Pennsylvania utility has inverted rates for residential customers during the summer and declining block rates during the winter. The Pennsylvania commission, however, is not encouraging electric utilities to use inverted rates.

A March 1978 Council of State Governments article entitled "State Initiatives for Electric Utility Rate Reform," indicated that reaction to inverted rates has been mixed. The article stated that several public service commissions reported positive feedback regarding the fairness to consumers and the effects of the rates on energy consumption. Potential pitfalls were also cited. Inverted rates appear to unjustly penalize customers who have high electric usage requirements for health reasons. Questions were also raised about the effect on utility cost and efficiency.

The Council's article also stated that the inverted price system implies that increased use leads to increased unit electricity costs. Utility costs, however, are more closely related to whether or not consumption takes place at peak or offpeak periods. Customers may respond to inverted rates by limiting overall consumption except at the peak. This would decrease base-load consumption and thus leave cheaper, more efficient base-load capacity idle causing increases in the unit cost of production which could cause service costs in all blocks to increase, thus raising the consumers' total bill.

SMALL COMMERCIAL CUSTOMER ELECTRIC RATES

The Subcommittee on Minority Enterprise and General Oversight expressed concern regarding small commercial customers' electric rates and the equitableness of billing commercial customers with a separate demand charge. The price that small commercial customers pay for electricity is affected by all three ratemaking steps:

--Determining the reasonableness of the total revenue requirements requested by the utility.

--Allocating the costs to the customer classes served by the utility.

--Determining the rate structure to be applied to recover the allocated revenue from individual users of electricity.

Each customer's electric bill reflects at least three charges--energy, demand, and customer. These charges are either assessed separately or combined into a composite rate, and reflect the variable, fixed, and customer costs incurred by the utility.

An energy charge reflects the variable cost incurred and includes fuel costs and operating and maintenance expenses. Variable costs change depending on the amount of electricity used.

A demand charge reflects fixed costs for items such as plant, equipment, depreciation, and insurance, associated with the utilities' investment in the system facilities needed to provide adequate electric service. The demand charge is based on the maximum kW demand placed on the utility system during a specified time period--usually 15 minutes to 1 hour --and may be reestablished in each succeeding billing period.

The demand charge for that peak period usage is a fixed cost for the entire billing period regardless of how frequently, or how seldom, the peak capacity is required.

An increasing number of utility systems identify a separate customer charge for one or more customer classes. This charge reflects those costs--including metering, billing and accounting--that do not vary with the level of electricity consumption. For customers who are not billed with a separate customer charge, these costs are generally incorporated into the initial block(s) of the energy charge, often as a minimum-use charge.

Most residential and some small commercial customers are usually billed with a composite rate that includes an energy charge and an average demand charge. The customer charge may also be included or it may be billed separately. In its simplest form the composite rate reflects an average cost of providing service and is multiplied by the total number of kWh of electricity used during the period to arrive at the total cost for the period.

Most industrial and large commercial customers who place greater demands on the system are billed with a separate demand charge. This charge is based on the peak usage reached during the period plus an additional energy charge reflecting the cost of producing the actual number of kWh of electricity consumed.

For those customers that have only a few peak needs during a billing period and relatively low consumption, the average composite rate offers the benefit of a lower total cost since they are not paying for unused capacity during most of the billing period. When customers with these usage patterns have their demand and energy charges billed separately the per-unit cost tends to increase. This problem is further amplified when a declining block rate structure is applied. Under declining block rates, both demand and energy charges are higher in the first blocks and decline as more capacity is needed and energy consumption increases. This is particularly applicable to larger commercial and industrial customers who tend to have lower per-unit costs than smaller users.

The application of the different rate structures varies among utilities and it is difficult to make general statements as to the effect on a class of customers. Our analysis of a number of electric rate schedules, however, showed a consistent pattern of utilities assessing a higher level of rates to small commercial customers than is assessed to comparable residential customers. A comparison of average rates charged each customer class tends to disguise this fact, because the advantages that accrue to large users are available to large commercial customers. Consequently, when rates for the various customer classes are averaged, commercial rates are reasonably comparable to residential rates but are considerably higher than industrial rates. These comparisons are shown in the table below for the three major customer classes and for utilities in the four States we visited.

Average Revenue Per kWh (1976)

Customer class	Michigan	New York	Pennsylvania	Wisconsin
	----------	cents	----------	----------
Residential	3.9	5.4	4.1	3.4
Commercial	4.0	5.6	3.8	3.4
Industrial	2.7	2.6	2.6	2.3

A different perspective emerges, however, when a comparison is made between small commercial and large commercial costs charged by individual utility companies. Utilities have different customer definitions and consequently we found no precise definition for the small commercial consumer. Many utilities, however, commonly refer to small commercial users as general service customers and to large commercial users as large general service customers. The price per kWh charged to their small commercial customers by a major utility in each of the four States visited is generally much higher than prices charged to their large commercial customers, as shown below.

Major utilities	Commercial class	
	Small	Large 1/
	---cents per	kWh---
Wisconsin Electric Power Co.	3.8	2.3
Detroit Edison Co.	4.9	4.3
Philadelphia Electric Co.	6.0	3.4
Con Edison	10.9	7.9

The comparisons shown above do not completely reflect the inequities that may or may not arise because a small commercial customer is assessed a separate demand charge. That question is not easily resolved because too much depends on the individual customer's pattern of use and its effect

1/These prices may also apply to industrial customers.

on the utility system providing the service. The higher rate levels imposed on the commercial customers do have a greater effect on the smaller commercial user because of rate structure differences which put a greater cost burden on small users. However, the utility will attempt to collect the same proportion of revenue requirements from the commercial customers regardless of whether it uses a composite rate or separates the various charges.

OBSERVATIONS AND MATTERS FOR CONSIDERATION

Commercial customers, and especially small commercial customers, have traditionally paid higher electric rates than other customer classes because it is claimed that they are responsible for the high-cost peak-demand periods. Commercial rates also may be higher because these customers have generally been excluded from revised rate structure schedules designed to reduce electric power consumption and minimize rate increases; and have not effectively intervened in rate hearing cases when costs are allocated.

Rate reform research and experimentation studies by Federal agencies, State commissions, and utilities to determine the impact of revised rate structures have been aimed primarily at residential and industrial customers and few studies have been done of small commercial customers. In view of the above, the Subcommittee may wish to encourage State commissions to conduct

--a more critical examination of utilities' cost-of-service studies to assess the validity of claims that commercial customers cause the higher-cost peak demands on the system, and

--rate reform impact studies to consider the effect revised rate structures will have on small commercial customers.

STATE COMMISSION COMMENTS

Pennsylvania was the only State commission to comment on matters discussed in this chapter. The Chairman said the commission is concerned about the impact of rate reform activities and cost-of-service studies on small businesses. The Chairman pointed out that the commission is encouraging several rate structure changes that would be beneficial to small commercial customers.

The Pennsylvania commission is also concerned about the absence of a current data base and proper allocation methods in formal rate cases and is contemplating a Generic Investigation into cost-of-service allocations and methodologies. The full text of the Pennsylvania commission's comment on this chapter are included on page 38 of this report.

JOSEPH P. ADDABBO, N.Y.
CHAIRMAN

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United States House of Representatives
Committee on Small Business
Subcommittee on Minority Enterprise
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2361 Rayburn House Office Building
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May 4, 1978

Honorable Elmer B. Staats
The Comptroller General
General Accounting Office
Washington, D. C. 20548

Dear Mr. Staats:

On February 28 last, this Subcommittee conducted hearings on, among other things, the effects of utility rate setting procedures on small businesses in the States of New York, Michigan, Pennsylvania and Wisconsin. At that time, GAO was present and offered excellent testimony with respect to its preliminary investigation into this subject area.

In accordance with our verbal request at the hearing, we now ask that GAO extend its investigation with respect to the four above mentioned States to cover the following areas:

1) A follow up and analysis of the results of State Commission audits of Pennsylvania utilities.

2) The number of state commissions that require utilities to use competitive procurement practices.

3) The use of captive coal mines by electric utilities--number, quantity of coal, regional trends, mine closures, and antitrust implications.

4) The ratemaking process within the four States in your report, including rate structures, demand charge implications for small businesses, state review of fuel costs, interruptible rates and their effects on small businesses, and cost/rate structure relationships.

5) The effects of rate structure re-design on small business energy costs.

Your compliance with this request by September 1, 1978, will be deeply appreciated.

With kindest regards and best wishes, I am

Sincerely,

Joseph P. Addabbo
Chairman

PUBLIC SERVICE COMMISSION
Daniel J. Demlow, Chairman
Lenton G. Sculthorp
Willa Mae King

WILLIAM G. MILLIKEN, Governor

DEPARTMENT OF COMMERCE

KEITH MOLIN, Director

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November 15, 1978

Mr. J. Dexter Peach, Director
Energy and Minerals Division
U.S. General Accounting Office
441 G Street, N.W.
Washington, D.C. 20548
Attn: Mr. Gerald H. Elsken

Dear Mr. Elsken:

Thank you for sending me a draft copy of your report on utility fuel procurement practices.

I find the GAO draft report concerning the efforts of the Michigan Public Service Commission to monitor the fuel procurement practices of our regulated utilities most disappointing. The analysis is extremely shallow generating broad sweeping generalizations based upon limited information and a clear lack of understanding of those activities recently initiated within the State of Michigan. In general, I would strongly recommend that the entire report be reexamined and rewritten to provide a more thorough and balanced approach to the problem. In particular, those sections describing Michigan's activities clearly warrant reexamination to more accurately reflect the situation within this state.

I am particularly distrubed with the approach taken by GAO researchers in conducting this particular study. Representatives from the Commission staff spent numerous hours working the staff of the GAO providing information and assistance with the analysis. Unfortunately, it appears as though little, if any, of this assistance proved fruitful. Most of the staff comments and suggestions were omitted completely from the analysis. I have been advised by Commission staff who provided assistance that it appeared from the very start that the study was in fact a facade. Conclusions seemed to be drawn at the very outset, with only those facts included that could in any way be construed to imply that the predetermined conclusions were in fact correct. After reviewing the draft report, I concur with staff assessment.

Failure to consider alternative solutions to the problem is strong evidence in support of our position. The report essentially concludes that the only effective way to scrutinize utility fuel procurement practices is through a full-scale audit approach. This conclusion is drawn without examination of the benefits and costs of such an approach. This narrow approach completely ignores alternative, and perhaps less costly, methods to obtain the desired results. In today's regulatory conscious environment, this standard bureaucratic accountant approach to problems is clearly unacceptable.

Although implied otherwise in the GAO report, Michigan has taken positive steps to more effectively scrutinize fuel utility procurement practices. Two years ago, a group was established within the Electric Division to deal specifically with fuel-related matters. The Fuels Planning Office currently has three full-time individuals. The Office collects and analyzes a wide array of data pertaining to all aspects of fuel procurement. In addition, the Fuels Planning Office researches fuel issues of importance, such as utility investments in captive mine operations, the "fair pricing" of captively mined fuels, and major fuel contract renegotiations. All major contracts covering fuel purchases are routinely reviewed. In my judgment, this clearly demonstrates our concern with regard to utility fuel activities. It also reflects a commitment on our part to initiate positive action. The informal approach that we have taken appears best suited to our particular needs. In the event major problems are uncovered, we, of course, have the option of initiating a full-scale audit. However, routinely scheduling such audits does not appear cost-effective at this point in time.

A report this superficial with no data to support overly-broad conclusions would be totally rejected by this Commission as having little or no value if performed by our staff. I would urge you to do the same.

I appreciate the opportunity to provide comments on this important matter.

Sincerely,

Daniel J. Demlow

Daniel J. Demlow

cc: J. Dexter Peach

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION
ALBANY

CHARLES A. ZIELINSKI
CHAIRMAN

EMPIRE STATE PLAZA

November 16, 1978

Dear Mr. Elsken:

Thank you for the invitation, extended in Mr. Peach's letter of November 6, to comment on pertinent portions of your draft report on the fuel procurement practices of electric utilities. Because time was so short, our comments were conveyed to you orally by Howard Tarler and Ronald Liberty of my staff; but I believe it may be useful to summarize them in writing here.

On page 7, you say that the usual procedure of New York utilities is "to solicit bids from several suppliers." While this is true in most cases, in many others contracts are negotiated with suppliers of the utility's choice and are not let for bids. We are usually aware of these cases and of the utility's reasons for not following the bid procedure.

On page 10, you say that two utilities were experiencing shortages in coal deliveries and generally made them up by purchasing coal on the spot market. We are aware of no important spot market purchases, and believe the implication that the companies were in trouble is inaccurate.

On page 12, the second line should read "utility fuel procurement practices." Most important, our staff has conducted an audit of the utilities' fuel procurement practices. The audit was completed in August, 1978 and was submitted as an exhibit in our generic fuel adjustment case, Case 27137. And although we now do not audit these practices "periodically," it has been recommended in the generic case that we do so.

GAO note: Page numbers in apps. III and IV refer to the draft report and do not necessarily correspond to this final report.

Page 16 asserts that New York companies are not involved in captive coal mine operations. We feel, however, that the arrangement at the Homer City Generation Plant, located in Pennsylvania and jointly owned by New York State Electric & Gas Corporation and Pennsylvania Electric Company, is essentially a captive coal mine operation. The utilities provide all the financing for the mines and receive all the coal output. The arrangements between the utility and the coal mines have been approved by us.

If I can be of further help in the preparation of your report, please let me know.

Sincerely,

Charles A. Zielinski

Mr. Gerald H. Elsken
United States General
Accounting Office
Energy Regulation Branch
941 North Capitol Street
Washington, DC 20548

 APPENDIX IV

PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH OF PENNSYLVANIA
HARRISBURG, PENNSYLVANIA

W WILSON GOODE
CHAIRMAN

December 18, 1978

Mr. J. Dexter Peach, Director
Energy and Minerals Division
U.S. General Accounting Office
441 G Street, N.W.
Washington, D. C. 20548

Attention: Mr. Gerald H. Elsken
Energy Regulation Branch
Room 3007
941 North Capitol Street

Dear Mr. Elsken:

I would like to thank you for giving me the opportunity to comment on the draft copy of Chapters 2 and 3 of "Electric Utility Fuel Procurement Practices and The Impact of Rate Reform Activities on Small Businesses". In general I concur with the comments made by the General Accounting Office in this draft report. However, it may be inappropriate to generalize on the weaknesses of State Commissions.

Regarding the issue of fuel procurement practices, I do not believe that the following comments apply to the Pennsylvania Commission:

> "We believe that State reviews of fuel-procurement practices need to be strengthened, especially in view of escalation clauses contained in most contracts . . . State commissions, therefore, need to periodically audit fuel-procurement practices and also audit fuel suppliers, if necessary, to assure themselves of the reasonableness of fuel costs." page 6, paragraph 1

> "State commissions that have electric utilities with captive coal operations should periodically audit transfer prices to insure the reasonableness of the prices". page 23, paragraph 1

This Commission's Bureau of Audits does conduct reviews of utility fuel procurement practices as well as audits of such practices. Further, this Commission does periodically audit transfer prices to insure the reasonableness of prices.

APPENDIX IV

With respect to the issue of the impact of rate reform activities on small businesses, I believe that the following comments do not apply to the Pennsylvania Commission:

> *"The reform has been gradual and primarily aimed at the large number of residential customers and high energy use industrial customers."*
>
> *page 25, paragraph 2*

> *". . .the Subcommittee may wish to encourage State Commissions to conduct a more critical examination of utilities cost-of-service studies to assess the validity of claims that commercial customers cause the higher cost peak demands on the system . . ."*
>
> *page 44, paragraph 2*

Personnel from this Commission's Bureau of Rates and Research have testified and are currently testifying that the following changes in rate structure be made which directly effect small commercial customers:

- *Expanding off-peak general service provisions to all general service customers regardless of demand.*
- *Expanding the interruptible rate currently available to residential customers, to commercial customers.*
- *Elimination of preferential rates within all customer classes.*

With regard to the issue of cost-of-service, the above mentioned staff are actively pursuing issues regarding the absence of a current data base and proper allocation methods in formal rate case proceedings. Because of the above this Commission is contemplating a Generic Investigation into cost-of-service allocations and methodologies.

To summarize, I believe it appropriate that the General Accounting Office report refer to "some State Commissions" or "certain State Commissions" rather than the general term "State Commissions" that is used throughout the report.

Sincerely,

W. Wilson Goode
Chairman

(30930)

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