THE PUBLIC UTILITY INDUSTRY

706

HEARING

BEFORE THE

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CONGRESS OF THE UNITED STATES

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WEDNESDAY, DECEMBER 4, 1974

CONGRESS OF THE UNITED STATES,
JOINT ECONOMIC COMMITTEE,
Washington, D.C.

The committee met, pursuant to notice, at 10 a.m., in room 1202, Dirksen Senate Office Building, Hon. William S. Moorhead (member of the committee) presiding.

Present: Representative Moorhead and Senator Proxmire.

Also present: Michael J. Runde, administrative assistant, and Walter B. Laessig, minority counsel.

OPENING STATEMENT OF REPRESENTATIVE MOORHEAD

Representative MOORHEAD. The committee will come to order.

This morning the Joint Economic Committee will hold a 1 day hearing on the electric utility industry. It is the intention of the committee to examine recent developments in the electrical utility industry which have caused hardships for both consumers and the utility industry. I hope we might be able to discover some suggestions for breaking into the high price, low rate of return spiral.

The electric utility industry has played and can be expected to play an increasingly important role in meeting this country's energy needs. Electrical generator capacity has doubled every 10 years for the past 40 years, and according to the Project Independence report, it will grow by another 150 percent by 1985. However, despite the increasing importance of electricity, this past year has not been a pleasant one for anybody associated with the electrical utilities.

Consumers have suffered on two counts: They are being asked to pay electric utility rates that average 20 percent higher than just 1 year ago. In some regions that are dependent on imported oil, the rate increases have been of even greater magnitude. Second, consumers are being asked to make up revenues that utilities have lost due to voluntary energy conservation efforts. I find it particularly disturbing that, in some cases, the energy conservation efforts of consumers have been rewarded with higher prices for electricity. In these cases, rate increases have been requested and often granted which kept utility bills high, even when consumption was reduced. In addition to being grossly unfair, I think these actions undermined the public spirited cooperation necessary for successful energy conservation.

Electric utility stockholders have also suffered a significant deterioration in the value of their assets. The value of utility stocks, which have traditionally been the source of retirement income, has been undermined by financial hardships experienced by some of the larger companies.

Finally, the electric utility companies, despite huge rate increases, have not been restored to sound financial health. In many cases the companies have been unable to convert higher rates into adequate earnings. Bond ratings have begun to suffer leading to higher interest costs and eventually higher prices ~~for the~~ consumer. The recession has further reduced revenues and exacerbated the financial squeeze. Somehow we must break this cycle of spiraling rates to the consumer and declining rates of return to the utilities.

There are several questions the committee intends to examine today which may contribute to an interruption of this vicious cycle. First it is essential that we develop more efficient methods for converting primary fuels to electricity. Now that fuel costs are at such exorbitant levels, we desperately need to improve on the present rates of conversion from fuel to electricity. I find it particularly disturbing that the efficiency of conversion has actually declined slightly in the last couple of years.

Second, we must use our generating capacity more efficiently, and thus reduce the per unit costs of generating electricity. Seasonal and daily peaks of demand require huge generating capacity which is only occasionally used to full capacity. If we can redistribute this peak load, we can greatly increase the efficiency with which we utilize capital facilities.

Third, we must examine more carefully the propriety of charging small residential users twice as much as large industrial and commercial users. To the extent that these preferential rates are cost justified, they should be allowed to continue, but if they are discriminatory, they should be halted.

Fourth, we must carefully examine the huge increases in the cost of constructing generating capacity, particularly nuclear plants, in an attempt to reduce the huge costs of capital equipment which is passed through to the consumer.

Finally, we will discuss the feasibility of coal and nuclear fuel playing a large role in the generation of electricity.

We are fortunate to have four expert witnesses to discuss these important questions. Our first witness will be Mr. John Nassikas, Chairman of the Federal Power Commission. The FPC regulates about 25 percent of the energy in the United States, including hydroelectric power and wholesale sales of electricity. Mr. Nassikas will be followed by a panel consisting of Mr. Gordon Corey, vice chairman of Commonwealth Edison Co. of Chicago; Mr. Frederick Mackie, president and general manager of Madison Gas and Electric Co.; and Prof. Murray Weidenbaum of Washington University in St. Louis. We will first hear from Chairman Nassikas. You may proceed in your own way.

Your entire statement will be made a part of the record, so we would appreciate it if you could summarize your remarks.

STATEMENT OF HON. JOHN N. NASSIKAS, CHAIRMAN, FEDERAL POWER COMMISSION, ACCOMPANIED BY EMMETT J. GAVIN, ASSISTANT TO THE CHAIRMAN; ROBERT G. UHLER, CHIEF, DIVISION OF ECONOMIC STUDIES, OFFICE OF ECONOMICS; AND J. PAUL DOUGLAS, ASSISTANT TO THE CHAIRMAN

Mr. NASSIKAS. Thank you, Mr. Chairman. The structure of my testimony relates first to the economic problems that are immediately facing the country, and then in summary form at the end of my statement, which I will repeat, some of the action programs that should be taken immediately to confront the economic crises. In between, there are about 35 pages or so of specific answers to the various questions that were posed. I will stay within the 5- to 6-minute framework in this statement and then respond to questions, if I may, Mr. Chairman.

I do appreciate the opportunity to be here. I would like to make a few general remarks to start out with concerning electric utilities, the industry, the Nation's economy, and energy policy.

First, chronic inflation and deepening recession, as you are all well aware, have ravaged the Nation's economy. The electric utility industry because of its size, capital intensiveness, and obligation to meet growth in customers' demands is particularly vulnerable to the shock of inflation and the drag of recession.

In a way, I might interpolate that the electric utility industry is really unable of itself to resolve problems of the general economy. Actions taken by the electric utility industry—it being a very large industry—including their rate structures, impact significantly on the economy. Nevertheless, basically they are confronted with problems of our economy which engulf their ability to navigate in this kind of sea.

Questions about investment tax credits for utilities and electric rate flattening, although important, pale in significance compared to the need for drastic, immediate, and wide-ranging policy innovations to combat the upward rush of prices and to stay the cold hand of unemployment. Joint congressional and Presidential actions are necessary to cope with the crisis. We are approaching a bleak Christmas season with prices still climbing and unemployment lines lengthening. Home building has stalled, automobile production has almost halted; and yet no significant across-the-board economic policy initiatives have been implemented. There have been some actions taken, but no across-the-board actions as necessary. Hard-nosed coordinated action by all sectors of Government is needed right now to avoid deepening economic problems.

Second, on a more positive note, we have made some progress in achieving essential energy reorganization. This has been a joint effort, again, of the administration and the Congress. The passage of the Energy Reorganization Act of 1974 marks a first step in the much-needed rationalization of Federal energy policymaking. The creation of the Energy Research and Development Administration (ERDA), Energy Resources Council (ERC) and the Nuclear Regulatory Commission (NRC) makes good commonsense and is long overdue.

I have recommended that we go even further in our energy institutional reorganization and combine the Federal Power Commission with the Nuclear Regulatory Commission and take over the holding company functions that the SEC now exercises under the Holding Company Act, and transfer these to the Federal Power Commission or to a duly organized agency, which for want of a better term I have named the Federal Energy Commission. We would add to that also the responsibility for issuing certificates of public convenience and necessity for all major energy systems, synthetic, natural gas and gasification of coal. We currently have jurisdiction, of course, over all liquefied natural gas imports to the United States and also interchanges of electric energy between Canada and Mexico. Staffing these agencies that have been created—and this is a fine step forward—and providing leadership for the Federal Energy Administration must be accomplished quickly. The Nation needed these institutional changes, we require the best managers available, and the United States urgently needs a consistent and comprehensive energy policy. Just as the electric utilities are buffeted by inflation and recession, they are tugged and pulled in several directions by the fragmented, contradictory, and ever-changing debate over national energy policies. I have seen this for 6 years. I think I can speak from the vantage point of having experienced changes in energy policy that we have had. This hurts the economy, and it hurts the utilities, and it hurts consumers.

It is particularly ironic and ill advised to subject a massive, vitally important sector of the economy—the electric power industry—to the twin terrors of inflation and recession; then impose stringent environmental standards that may cost more than they are worth; and "encourage" first a switch to oil, and now a "return" to coal. It is no wonder that electric utility industry leaders and at least some regulatory commissions question the effectiveness of our Federal Government's energy policymaking process.

I will skip over the answers to the questions, as I said at the outset, if I may, Mr. Chairman.

In closing, I would like to suggest for your consideration an agenda for action that would assist in alleviating the financial plight of the electric utility industry as well as contribute to shoring up our sagging economy.

I don't think any of these matters are new. I don't claim that they are novel. I just think that they are important.

First: Economic policies obviously must be adopted to avoid runaway wages, prices, and profits.

Second: Tax relief for lower income groups must be considered as a part of tax reform legislation.

Third: Jobs in the public sector should be strengthened, not cut back as local budgets are pinched. Federal aid should be provided.

Fourth: Specific additional relief for adversely impacted industries such as housing, automotive, and electric utilities should be devised.

Fifth: And this is directed at the electric utility industry rather than urging action by Congress or the administration, rate design changes such as peak load and long-run incremental cost pricing should be sponsored by utilities before State Public Utility Commissions. This was done in the *Madison* case in Wisconsin and there will be a witness here on that, and also it was done in the State of Vermont, which is my neighboring State. I am from New Hampshire. I wish they had done it in New Hampshire rather than in Vermont, because it is a rather salutary and innovative measure that the Vermonters succeeded in adopting.

Sixth: And of great importance, in the short run, incentives for energy conservation should be legislated—voluntary as a rule, but backed by standby mandatory provisions.

Seventh: Broad policies to encourage the production of domestic energy supplies should be enacted—and this is, of course, one of the single most important recommendations I could make, Mr. Chairman. We should deregulate new supplies of natural gas under carefully monitored conditions with protective covenants for consumers. I can give you that in detail if you wish, later on. It is very important to allow economic forces to allocate or ration our gas resources, which are about one-third of all energy in the United States, rather than to have myself and my four colleagues and the staff trying to ration centrally and not succeeding in doing a very good job, particularly because of a very restrictive statute which Congress enacted.

Eighth: Vigorous efforts to enhance competition throughout the economy through antitrust enforcement, changes in regulatory practices, and also greater public disclosure of corporate activities should be encouraged.

There is relatively little a regulatory agency can do when a utility's costs escalate over 25 percent in a year. Certainly in the short run, there is very little to do. Similarly, as interest rates touch hundred-year highs, regulators are stymied. As stock prices collapse, the clamor for higher rates of return is deafening and, at times, advisable. When consumers of electric power revolt from paying higher rates for less electricity use, which you mentioned in your opening statement, regulators can hardly become salesmen for the industry to implore consumers to pay more so that revenues will be adequate to finance a going enterprise. The reward for patriotism sometimes seems to end up in higher rates rather than lower rates.

Electric utility executives and regulatory commissioners stand at the vortex of inflation—hardly the cause but surely suffering the effects of a troubled economy. Moreover, these prime users of energy sources and vital suppliers of electric power have little control over national energy policies. Again, their dependency on the viability of the national economy underscores their vulnerability. Fortunately, there are many instances where the interests of the electric industry and their customers coincide. Halting inflation is the most obvious but we cannot discount the dramatic impact of multiple policies such as reducing the rate of energy and electricity growth, comprehensive conservation for more effective utilization of resources, rate design reform, increased power pooling, regional planning and interconnections to reduce planned capacity, improvements in technology of major generating and transmission systems, and finally, a research and development program by government and industry to improve present energy utilization and to develop new forms of energy.

I will be happy to respond to your questions, Mr. Chairman.

[The prepared statement of Mr. Nassikas, together with response to questions posed by Representative Moorhead follow:]

Prepared Statement of Hon. John N. Nassikas

Mr. Chairman and members of the committee: I appreciate this opportunity to appear before the Joint Economic Committee in response to your emergency inflation study. My testimony will focus on the questions posed in Congressman Moorhead's letter of November 20, 1974. Before answering these questions, however, I would like to make a few general remarks about the electric utility industry, the nation's economy and energy policy.

First, chronic inflation and deepening recession, as you all are well aware, have ravaged the nation's economy. The electric utility industry because of its size, capital intensiveness, and obligation to meet growth in customers' demands is particularly vulnerable to the shock of inflation and the drag of recession. Questions about investment tax credits for utilities and electric rate flattening, although important, pale in significance compared to the need for drastic, immediate and wide-ranging policy innovations to combat the upward rush of prices and to stay the cold hand of unemployment.[1] Joint Congressional and Presidential actions are necessary to cope with the crisis. We are approaching a bleak Christmas season with prices still climbing and unemployment lines lengthening. Home building has stalled, automobile production has almost halted and yet no significant across-the-board economic policy initiatives have been implemented. Hard-nosed coordinated action by all sectors of government is needed right now to avoid deepening economic problems.[2]

Second, on a more positive note, we have made some progress in achieving essential energy reorganization. The passage of the Energy Reorganization Act of 1974 marks a first step in the much needed rationalization of Federal energy policy making. The creation of the Energy Research and Development Administration (ERDA), Energy Resources Council (ERC) and the Nuclear Regulatory Commission (NRC) makes good common sense and is long overdue. Staffing these agencies and providing leadership for the Federal Energy Administration must be accomplished quickly.[3] The nation needed these institutional changes, we require the best managers available, and the United States urgently needs a consistent and comprehensive energy policy. Just as the electric utilities are buffeted by inflation and recession, they are tugged and pulled in several directions by the fragmented, contradictory, and ever-changing debate over national energy policies.

It is particularly ironic and ill-advised to subject a massive, vitally important sector of the economy—the electric power industry—to the twin terrors of inflation and recession; impose stringent environmental standards that may cost more than they are worth; and "encourage" first a switch to oil and now a "return" to coal. It is no wonder that electric utility industry leaders and at least some regulatory commissions question the effectiveness of our Federal government's energy policy making process.

I have provided below answers to Congressman Moorhead's specific questions. Additional data and information are available in the references cited as footnotes.

Response of Hon. John N. Nassikas to Questions Posed by Representative Moorhead in the Letter of Invitation To Testify

Question 1A. What long-term rate of growth in electricity generating capacity do you anticipate will be necessary to meet future demands for electricity?

Answer. Throughout this century the long-term compound rate of growth in

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[1] For an analysis of the relative effect of various policy alternatives see "Public Policy Innovations for the Electric Utility Industry"; Remarks of John N. Nassikas before a meeting of State Regulatory Commissioners and Federal Officials; Washington, D.C.; September 11, 1974.

[2] "Importance of Electric Utilities in the Economy," Keynote Address by John N. Nassikas at the Financial Seminar, Electric Council of New England; Boston, Massachusetts; October 31, 1974.

[3] "Regulatory Perspectives on Energy Conservation"; Remarks of John N. Nassikas before the Council Meeting of the International Gas Union; Solihull, England; November 14, 1974.

electricity energy requirements and peak load demand has been about 7 percent per year. This is approximately twice the long-term rate of growth of the econony as a whole and of total energy consumption. The higher rate of growth for electricity reflects its replacement of older energy forms, such as steam engine driven line-shafts in factories, and the fact that many of the new forms of energy consumption require electricity, such as refrigeration, television, and the space conditioning of large building complexes. It has long been recognized, however, that the rate of growth in electricity consumption will converge to the national rate of growth in total energy consumption, as the various markets for electricity applications become saturated and the share of total energy consumption represented by electricity continues to increase (i.e., the emergence of the "all-electric" economy).

The Commission's 1970 *National Power Survey* projected that the historic growth trend in peak load and generating capacity would continue at a rate of about 7 percent per year into the early 1980s, with a gradual decline in growth rate to about 5 percent per year by the year 2000.[4] That projection was based on the continuation of historic national economic growth trends, the availability of adequate supplies of fossil energy and the rapid growth of nuclear power at costs competitive with coal and oil fired power. Such an average trend line does not represent a projection for a specific year because fluctuations in growth rate around the long-term trend are normal. For example, the year to year growth in electricity consumption has always been sensitive to the overall level of business activity as well as weather conditions. During the past year, however, the very large increases in the costs of oil and coal and other inflationary forces have increased electricity prices greatly. In 1974, customer reaction to these higher prices, the rekindled awareness of energy conservation benefits, mild weather, and the slow-down in the economy have resulted in a minimal (i.e., only a fraction of 1 percent) increase in electric energy production.[5] Peak loads have also increased much less than usual, perhaps only about 2 percent.

It is impossible, on the basis of available data, to sort out the contribution of each causative factor to the overall reduction of electric power growth. At least an additional year of experience and data are needed to confirm whether a permanent reduction in the long-term growth rate has occurred. I believe, however, that these recent developments indicate that the trend in load growth probably will be below the 1970 projection at least over the near term.[6]

If we utilize our coal and uranium resources to meet future electric power needs and displace oil and natural gas for that purpose, it may be that the growth rate in the electric utility industry may continue at a 7 to 8 percent rate over the next two decades while we reduce the overall energy growth rate to 2 percent through conservation practices.

Question 1B. What has been the impact of recent energy conservation measures on producing a growth rate that differs significantly from historical standards?

Answer. As pointed out above, the 1974 growth in electric energy production has been well below the historic trend. And, as noted, we cannot distinguish the portion of the reduction due to conservation, as distinct from that reflecting lower levels of business activity or customer reaction to higher prices. During the oil embargo of last winter, many utilities noted that voluntary customer conservation was reducing energy consumption by 7 to 10 percent, as compared to normal expectations. In one city (i.e., Los Angeles), with the assistance of mandatory measures, electric energy consumption was reduced more than 20 percent. Following the relaxation of the oil embargo, there was a noticeable lessening of "conservation" savings. The summer of 1974 was expected to be a test of whether consumer conservation efforts would include reducing air conditioning use on extremely hot days. The summer, however, was cooler than usual in many areas and the generally lower-than-expected peak loads experienced cannot be considered to be a conclusive indication. In short, it is not yet known

[4] *The 1970 National Power Survey*, Federal Power Commission, December 1971. More recent estimates are available in "Report to the Federal Power Commission by the National Power Survey Technical Advisory Committee on Power Supply" and "The Report of the Technical Advisory Committee on Fuel." September 1974.

[5] Federal Power Commission News Release No. 20722; October 8, 1974 and recent issues of Edison Electric Institute, *Electric Output*.

[6] This view is reflected in the draft report of the National Power Supply Technical Advisory Committee on Finance, Mr. Gordon Corey, Chairman.

whether the reduced electric energy and peak load demand growth of the past year represents the beginning of a new trend or a major, but temporary, departure from the historic trend caused by a cyclical economic downturn or other factors.

Question 1C. To what extend can increased implementation of peak load pricing and long-run incremental cost pricing impact the demand for electricity generating capacity?

Answer. Ideally, the general adoption of peak load pricing for electric energy could reduce the ratio of peak load to average load. This would increase system load factors and reduce the required amount of generating capacity. This reduction in required generating capacity, however, would be of the so-called peaking type which has the lowest capital costs. I have suggested elsewhere that the concept of peak load pricing is an idea deserving support.

Long-run incremental cost pricing (LRIC) may be defined as the incremental or marginal cost of added capacity and output which can reasonably be anticipated to meet foreseeable demand over a number of years. The concept will associate costs of providing service with rates charged to consumers. The theory coincides with the economic precept that an optimum allocation of resources results from pricing goods and service equal to their marginal costs of production. Rates to various classes of users may increase as costs of providing service are ascribed to each class, thus promoting customer efficiency in electricity utilization. We may further reduce the rate of growth in electricity demand and, ultimately, reduce the required electric generating capacity. I have recommended rate flattening as an alternative to declining blocks where cost justified. The quantitative impact of LRIC pricing and peak load pricing on capacity requirements is dependent upon the price elasticity of electricity demand, the cost of alternative energy sources, and other factors. These relationships are not sufficiently well established to enable specific predictions; however, research and actual experimentation are underway.[7]

Question 1D. What other measures besides peak-load pricing can we use to improve the rate of capacity utilization in the electric utility industry?

Answer. In Japan, following World War II, there was an acute shortage of electric generating capacity for many years. As a consequence individual industrial and commercial facilities were assigned maximum electric load levels. Presumably some comparable form of rationing or a greater use of "interruptible" service could be employed to further increase system load factors and reduce new capacity requirements. Automatic load shedding computer programs for large buildings are now commercially available. Billing industrial accounts on a coincident peak basis also would help. A differential rate between seasonal peaks—as in Vermont[8]—is worth considering. An expansion of interconnected regional grids and power pools and better regional planning will reduce required reserve margins and overall capacity to meet loads.

Question 2A. What factors are responsible for the slight decline experienced by the industry in the efficiency with which it converts fossil fuel to electricity?

Answer. It is presumed that this question relates to the trend in the national average heat rate for fossil fuel steam-electric plants.[9] Over the past ten years the average heat rate has remained in the neighborhood of 10,500 Btu per kilowatt hour with a variation of about 1 percent. In the preceding 20 years, the heat rate had been reduced by about one-third. There was a slight increase from the low figure of 10,398 in 1968 to 10,478 in 1971 but in 1972 the figure dropped again to 10,379 (Data for 1973 are not available). Although the figures do not show any discernable increase in heat rate (i.e., a decline in efficiency) in recent years, they do indicate the end, in the early 1960s, of the improvement which had been steadily occurring since the beginning of the century. Two factors are involved in this topping-out of efficiency, one technical and one economic. The technical factor relates to the inherent efficiency limitations of the steam thermodynamic cycle. By the early 1960s, increased temperatures and pressures, which provide improved efficiency, had gone as far as possible with

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[7] Wisconsin Public Service Commission, 2–U–7423; August 8, 1974. Methodological problems have been outlined by Lester D. Taylor, University of Arizona and Louis Guth, National Economic Research Associates.

[8] See Order No. 3744. State of Vermont, Public Service Board, Petition of Central Vermont Public Service Corporation, *et al.*

[9] *Steam Electric Plant Construction Cost and Annual Production Expenses*, 1972, Federal Power Commission.

the materials available. And, modifications of the simple cycle, such as use of increased numbers of reheat stages and regenerative heat exchange systems, had been well developed and applied. The economic factor was fuel cost savings which are limited by the increased capital and maintenance costs of the more efficient equipment, averaged over the plant's lifetime.

In recent years, electric utilities have used substantial amounts of gas turbine peaking capacity, which typically has much poorer heat rates than a modern steam system. This gas turbine equipment, however, provides only a few percent of the total electric energy and, therefore, its operation has not significantly affected the national average heat rate. Substantial reductions in heat rate (i.e., improvements in efficiency) are possible with a combination of gas turbine and steam turbine, commonly known as combined cycle units. Practically all such units, however, require oil or natural gas as the primary fuel and these fuels are of very doubtful availability for future new generating plants. This is particularly true given the President's call for conversion of oil fired plants to coal and greater use of nuclear energy.

Higher fuel prices increase the incentive for more efficient fossil fueled plants. A large number of new coal fired plants will be needed and these will be of the most efficient type with heat rates of 9000 Btu per kw-hr or less. As they are added to the population of existing fossil-fueled plants, the average heat rate will improve.

Question 2B. Have automatic fuel adjustment clauses been a factor in that they might cause the industry to substitute energy-intensive generating processes for capital-intensive processes?

Answer. Most electric utility systems operate on "economic dispatch", that is, additional increments of required generation are assigned to those generating units with the lowest incremental power cost. In general, this means that utilities will make maximum use of the least expensive fuel available. The existence of fuel clauses does not diminish this objective because higher prices discourage consumption and may cut revenue and income. These clauses do not lessen the incentives for utilities to achieve the lowest possible generating costs. On the other hand, the design and construction of new generating plants with efficiencies matched to the new higher fuel prices require at least four to five years. Thus, there has not been sufficient time for the industry to react to the recent sharp fuel price increases through addition of high efficiency units.

Question 3A. What factors are responsible for the increasingly high cost of electricity generating capacity?

Answer. The causes of higher generating capacity costs are generally well understood and include a number of factors [10] such as higher equipment costs, inadequate quality controls, impact of inflation on labor and materials, cost of money, environmental protection costs and regulatory lag.

New technologies and national environmental and energy policies have intensified the capital requirements of utilities in base load generating plants. For example, nuclear units are 25 to 35 percent more expensive than conventional units in base cost,—man-hours, materials and equipment—even though lower nuclear fuel costs will result in lesser power costs over a 30-year plant lifetime. In each of the past three years, more than half of the new capacity ordered has been nuclear, so that this factor alone accounts for a substantial portion of the construction cost increase. In addition to a greater base cost, nuclear plants take several years longer to build than conventional units. This allows escalation (i.e., inflation) to increase costs more than with conventional units and causes the allowance for funds used during construction to be much greater than for conventional units. Thus, a nuclear unit ordered today may be recorded on the utility's books at twice the cost of a conventional unit of the same capacity ordered at the same time.

Second, conventional fossil-fueled steam generating units are more expensive than before, aside from the direct construction cost increases. The cheapest steam generating unit has traditionally been one fired by natural gas, with oil and coal-fired units progressively more expensive. Supplies of natural gas for electric power generation, however, are declining or not available and practically no new base load gas fired units are planned.[11] Further, the oil import and fuel

[10] *Electrical World*, "18th Steam Station Cost Survey," Leonard M. Olmsted; November 1, 1973.

[11] *Electrical World*, "13th Steam Station Design Survey," Leonard M. Olmsted; November 15, 1974.

price problems have caused the utilities, with the urging of the Federal government, to order coal fired units to the greatest extent possible. Today, coal units are considerably more costly than heretofore because of new environmental control provisions. In addition, coal units will sustain further heavy cost increases if planned environmental regulations become effective.

Question 3B. Are there any specific actions that the Government or the electric utility industry might take to reduce these tremendous increases in cost?

Answer. In addition to peak load and incremental pricing to reduce future capacity needs, further interconnections and regional planning requiring lower reserve margins will enable the electric utility industry to provide reliable service at less cost. A comprehensive and continuing conservation program must be instituted by Government and the electric utility industry—thus enabling essential needs to be supplied with fewer kw of capacity. Because the biggest single contributor to the increase in costs of generating plants is the continuing inflation, those actions which reduce the inflation rate will have the greatest beneficial effect.[12] Certainly the principal actions to reduce inflation are in the domain of Government. The recent deferments and cancellations of utility orders for new plants because of financial difficulties will reduce the inflationary pressures on plant construction costs.

One consequence of the sharply increased plant construction costs may be a shift from more efficient plant designs to ones that are less capital intensive, less complex and less efficient. Thus, while the increased fuel prices are an incentive for more efficient plants, construction cost increases may result in less efficient plants.

Question 4. What impact will President Ford's proposals for liberalization of the investment tax credit have on the electric utility industry? Will the increase from four percent to ten percent make a significant contribution to internally-generated cash flow? What will be the impact of making the investment tax credit refundable after three years? What will be the impact of the refundable feature on decisions by state regulatory agencies?

Answer. In 1973, the electric utility industry generated investment tax credits amounting to about $380 million. Due to the absence of taxable income and the 50 percent income tax liability limitation, the industry was able to utilize only about $274 million of these credits. If a seven percent investment tax credit rate, had been used in 1973, additional credits of $284 million would have been generated, of which the electric industry would have been able to utilize about $104 million. The additional credits generated from an increase in the tax credit rate from four to ten percent would have been in excess of $568 million. The industry would have been able to utilize only about $175 million of these credits generated as credits against income taxes payable.

If the credits not applied against taxable income were refunded after a three-year period, the electric utility industry would be entitled to a refund of about $106 million on the basis of tax credits generated but not utilized in 1973. An increase in the rate to seven percent would have produced $180 million in unutilized, and therefore refundable, additional credits. If the rate were increased to ten percent, the additional refundable credits would have been approximately $393 million greater than those actually generated and not utilized at the current rate in 1973.

In summary, based on 1973 data, the electric utility industry's income taxes would be reduced or the industry would be entitled to refunds in amounts ranging from $104 million to $674 million depending on the rate of investment credit selected and the inclusion of the refundable credit provision. Whether cash flow of the industry would be augmented by these amounts depends on the rate treatment afforded the credits by regulatory agencies having jurisdiction over the industry's rates.[13]

Under current regulations, regulatory agencies are not restricted from using the amounts of investment tax credits utilized as tax reductions in determining the cost of service for utilities under their jurisdiction. Responses to a survey on the rate treatment afforded investment tax credits showed that 44 regulatory

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[12] *An Analysis of the Electric Utility Industry's Financial Requirements 1975–1979* by Robert G. Uhler, Federal Power Commission, September 1974.

[13] An earlier but more comprehensive financial analysis was prepared in September 1974. "A Study of the Electric Utility Industry"; Federal Power Commission, Office of Accounting and Finance; September 1974.

bodies utilized the credit in setting the rates of utilities under their jurisdiction either by the use of actual taxes or by utilizing a portion of the credit related to the annual amortization of the credits to operating income.[14] Based on this information, cash flow of utilities will not necessarily increase if state regulatory commissions use any additional credits as reductions in the cost of service, either directly or as a reduction of the utility rate base, unless such practices were prohibited by tax regulations.

Question 5. What will be the impact of recession on the financial problems of the electric utility industry? Will the present recession ease or exacerbate the financial problems of the electric utilities?

Answer. Current financial problems arise from the inability of the electric utility industry to provide a competitive rate of return on new stock offerings during a period of high inflation. The sale of some stock, in addition to bond offerings, is an essential requirement for utilities to maintain the debt-equity ratios required by the financial markets. Utility problems in securing financing should be eased somewhat with a decline in the general level of interest rates. And, to the degree that a recession will help bring down interest rates, short-run utility financing problems might be made easier. On the other hand, a recession and reduced business activity typically mean lower electric power sales and reduced utility profit margins. Poor earnings would tend to make financing more difficult. In addition, a recession has often been followed by a sharp economic upswing. This could strain electric generating capacity and force utilities into rapid and expensive capital construction projects.

In view of these countervailing factors, it is difficult to generalize on whether the present recession will ease or exacerbate electric utility financial problems. In simple terms, a brief recession whose chief impact is to check the rapid rate of inflation, might well ease some utility financial problems. A deeper and longer recession, however, could damage profit margins and ultimately lead to greater financial difficulties. Overall, the electric utility industry and its consumers will benefit far more from a prosperous economy with inflation under control than from recession.

Question 6A. Over the past year the construction of a large amount of generating capacity has been delayed or even canceled. What impact will these delays have on the ultimate cost of this generating capacity?

Answer. As indicated in my response to Question 3, inflation has been a major factor in the steadily increasing cost of new generating capacity. A basic effect of delaying new capacity, therefore, will be to increase its ultimate cost. The overall effect of delaying new capacity on the total cost of power is complex and will vary significantly from case to case. If there has been a slowing down in load growth, the extra cost of facilities completed on schedule but not fully utilized may exceed the construction cost increases due to inflation. If the needed power is available for several years from neighboring utilities which have excess capacity, there may also be an overall economic advantage in deferring construction of new capacity, even though its ultimate cost will be increased.

Question 6B. Will these delays significantly jeopardize the reliability of service offered by the electric utility industry?

Answer. The impact of the deferrals and delays of new capacity upon electric power reliability is strongly dependent upon the future growth of peak loads which is now somewhat indeterminate. If load growth is sufficiently slow, the deferments may not impair the reliability of electric service. On the other hand, because of the long construction periods for new generating capacity, the deferments could result in an electric supply inadequate to meet demands if historic load growth rates were reestablished. In short, while the extensive 1974 deferrals and cancellations of planned new capacity cannot be described as surely leading to reduced reliability of service, they have certainly greatly increased the possibility of inadequate reliability. The Bureau of Power is now reviewing this matter in detail.[15]

Question 6C. What are the major factors causing these delays and cancellations (conservation, financial difficulties, recession)?

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[14] *Federal and State Commission Jurisdiction and Regulation of Electric, Gas, and Telephone Utilities*, 1973, Federal Power Commission.

[15] *Effects of Generating Unit Construction Stoppage on Adequacy and Reliability of Power Supply*, Federal Power Commission, Bureau of Power Staff Report September 1974.

Answer. The biggest factor in the 1974 delays and cancellations of new electric facilities is the unfavorable financial environment and the resultant difficulties faced by the electric utility industry in acquiring new capital. While some utilities are reducing their projections of peak load for the 1980 period, this appears to justify only a small portion of the announced cutbacks in plant. In many cases of capacity deferments, the utilities are reducing their reserve margin objectives from the preferred 20 percent to as low as 12 percent. The utilities are not certain of the long-term continuation of voluntary conservation nor the timing of the recession. Conservation and recession have been lessor factors in the utilities' decisions to defer new capacity.

Question 7. To what extent are the preferential rates received by large commercial and industrial users justified by cost considerations? If these rates are not totally justified by cost considerations, what would be the impact on rates charged residential users if the rates charged per kilowatt-hour for each user were made equal to the costs of providing that electricity to the user? Do many rate structures still reflect the promotional attitude taken by utilities in the past?

Answer. Historically, electric power rates have been structured so that large commercial and industrial customers paid less per kilowatt-hour than small users. Large users generally have a better load factor than other customer classes. Their demands, however, tend to be more price elastic. To the extent that low rates attract these large loads, average unit costs could be lower so that other customer classes are relieved of some of the fixed costs they would otherwise have to bear.[16]

The impact on rates to residential customers as a result of increasing rates to large commercial and industrial users will depend on the response of such users to changes in their rate levels. Absent any loss of load, increased revenues obtained from large commercial and industrial users could result in reduced rates for residential customers. Significant rate increases to the large users, however, could provide a substantial economic incentive for large volume customers, whose demands are relatively more price elastic, to turn to alternative energy sources or to reduce their usage of energy. In that event, the remaining customers, including residential users, whose demands are comparatively inelastic, would probably be burdened with a larger share of the fixed charges on plant facilities.

Higher electric rates to industrial users may not only increase their production costs but may also cause curtailed energy usage, which could have an adverse effect on the efficiency of their plant operations. To the extent that their control of the market permits, the result of this would undoubtedly be higher prices for their products and services. This might offset the benefits that would accrue to residential customers as a result of their lower electric rates.

The ability of electric utilities to achieve economies of scale is dependent upon increasing demands for power to justify the installation of large-sized bulk power supply facilities. The loss of the load of large users who could turn to other energy sources or who may find on-site generation to be to their advantage, could deprive many utilities of the benefits of economies of scale.

It is necessary to distinguish cost justified "promotional" rates which provide for decreasing charges for increased usage, from "promotional" rates which are priced below costs primarily for the purpose of competing for loads. The purely promotional aspects of electric rates priced below costs to encourage consumption do not now represent quite as significant a factor in ratemaking as in the past. Public attention has been focused on the ability of the electric industry to deal with the shortage of electric power and the need to conserve natural resources. Similarly, the industry and regulatory agencies have focused recently on the need to design rates that lead to an optimum allocation of resources. Greater effort has been made to design rates which are more closely related to the incurrence of costs experienced by the utilities to render the service. A few systems are experimenting with the rate schedules in which higher rates are charged during seasonal peak periods. Several state commissions have given consideration to various modification of rate design to flatten rates and to base rates on time-of-day usage.[17] It should be noted that rate differentials between

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[16] Alfred E. Kahn, *The Economics of Regulation* 1970.

[17] Wisconsin Public Service Commission, 2-U-7423; August 8, 1974 and Vermont Public Service Board, No. 3744; September 20, 1974.

large and small users have been somewhat narrowed during the recent period of fuel clause increases because the operation of fuel adjustment clauses has placed a proportionately greater burden on the industrial and commercial users.

The Federal Power Commission issued a Notice of Proposed Rulemaking in April 1974 in Docket No. RM74-20 in which we propose to revise our Regulations under the Federal Power Act to provide for the filing of rate design information when rate schedules are initially filed or when they are proposed to be changed. Among other things, we are asking that where the rates contain more than one block, a detailed explanation be submitted indicating the rationale for the blocking and the cost, conservation or other considerations upon which such blocking is based. The explanation of the rate design will serve to focus attention on the objectives of rate design and the economic foundations underlying such design.

In closing, I would like to suggest for your consideration an agenda for action that would alleviate the financial plight of the electric utility industry as well as shore up our sagging economy.

First, economic policies must be adopted to avoid runaway wages, prices and profits.

Second, tax relief for lower income groups must be considered as a part of tax reform legislation.

Third, jobs in the public sector should be strengthened, not cut back as local budgets are pinched. Federal aid should be provided.

Fourth, specific additional relief for adversely impacted industries such as housing, automotive and electric utilities should be devised.

Fifth, and this is directed at the electric utility industry rather than the Congress, rate design changes such as peak load and long run incremental cost pricing should be sponsored by utilities before State Public Utility Commissions.

Sixth, and of great importance in the short run, incentives for energy conservation should be legislated—voluntary as a rule but backed by standby mandatory provisions.

Seventh, broad policies to encourage the production of domestic energy supplies should be enacted—e.g., a carefully monitored deregulation of new natural gas with protective covenants for consumers.

Eighth, vigorous efforts to enhance competition throughout the economy through antitrust enforcement, changes in regulatory practices, and greater public disclosure of corporate activities should be encouraged.

There is relatively little a regulatory agency can do when a utility's costs escalate over 25 percent in a year. Similarly, as interest rates touch hundred year highs, regulators are stymied. As stock prices collapse, the clamor for high rates of return is deafening and, at times, advisable. When consumers of electric power revolt from paying higher rates for less electricity use, regulators can hardly become salesmen for the industry to implore consumers to pay more so that revenues will be adequate to finance a going enterprise. Electric utility executives and regulatory commissioners stand at the vortex of inflation—hardly the cause but surely suffering the effects of a troubled economy. Moreover these prime users of energy sources and vital suppliers of electric power have little control over national energy policies. Again, their dependency on the viability of the national economy underscores their vulnerability. Fortunately, there are many instances where the interests of the electric industry and their customers coincide. Halting inflation is the most obvious but we cannot discount the dramatic impact of multiple policies reducing the rate of energy and electricity growth, comprehensive conservation for more effective utilization of resources, rate design reform, increased power pooling, regional planning and interconnections to reduce planned capacity, improvements in technology of major generating and transmission systems, and finally a research and development program by government and industry to improve present energy utilization and to develop new forms of energy.

Representative MOORHEAD. Mr. Chairman, that was an excellent presentation. I take it that your first message to this committee is that we should cure the problems of the general economy so that the problems of the utility industry can be solved more easily. Is that correct?

Mr. NASSIKAS. Yes; it is. That is exactly right.

Representative MOORHEAD. In your testimony, you state that there have been no significant across-the-board economic policy initiatives. I assume that the ones you are suggesting that we adopt are listed in your prepared statement?

Mr. NASSIKAS. Yes; they are. I didn't say this in my prepared statement, but really, America has to regain confidence in itself, and I think that we had better all recognize the merits of our U.S. system and maybe the economy, through faith, will improve. We need actually more than faith. We need action both by the Congress and the administration. We need more action from the Federal Power Commission. I will include ourselves in it.

Representative MOORHEAD. I do feel that the further I get away from Washington and New York, the more I sense confidence in the country.

Mr. NASSIKAS. Excellent.

Representative MOORHEAD. Wall Street and Pennsylvania Avenue have less confidence than the mainstream of America, with the possible exception of Detroit. The automobile industry is in really serious trouble, as you point out in your statement.

I was also interested, in your proposal about a Federal Energy Commission.

Mr. NASSIKAS. Yes, sir.

Representative MOORHEAD. I think it would be helpful if that proposal were written as legislation, although it would probably be referred to another committee. You would not include the new Energy Research and Development Administration?

Mr. NASSIKAS. No; I would not. I think the Energy Research and Development Administration has its own mission and objectives. Basically, my concept is to combine the economic regulatory functions of two major energy commissions rather than the research and development functions, which should remain, I think, and be separately administered by ERDA.

Representative MOORHEAD. Now, also in your testimony, you discuss the investment-tax-credit proposal.

Mr. NASSIKAS. Yes, sir.

Representative MOORHEAD. Fundamentally, your point is that the utilities should be treated on the same basis as other industries. Is that correct?

Mr. NASSIKAS. I believe that that is a principle of equity that should be adopted. When you are dealing with a multibillion dollar industry and multibillion dollar revenues, the impact of the investment tax credit is quite nominal, but it will help. A few million dollars will help, and it will help utilities to improve their cash flow and to generate funds internally rather than going to external markets at a time when it is virtually impossible to market equity securities in today's climate, even if earnings of utilities are good.

Representative MOORHEAD. I agree with your opinion that utilities should be treated as other industries. I am very much disturbed, however, by the refunding aspect of the administration's proposal. As you point out—and you are just talking about the electric utility industry when you provide for refunding the unused portion of the investment credit, it could amount to a considerable sum of money. Based on 1973 data, refunds of $674 million can be expected and this is without any of the stimulus to investment that is the underlying reason for the investment tax credit. Would you care to comment?

Mr. NASSIKAS. Well, I think your observation is very well taken, Mr. Chairman. The only caveat I would offer is that whether the cash flow of the industry would be augmented by the entire $674 million depends on the rate treatment afforded their efforts by the regulatory agencies. If the regulatory agencies don't give the utilities the benefits, then the purpose of the investment tax credit is not realized. If these refunds in effect do not improve the cash flow of the utilities, then there is a problem.

I wanted to point out that there is this refund problem. It is a question of how the State regulatory agencies treat the refunds. That is what I wanted to say.

Representative MOORHEAD. My point goes a little beyond the utility industry. If we establish investment tax credits, which we have in the past and which we propose to increase, the purpose is to encourage investment-increased capacity.

Mr. NASSIKAS. Yes, sir.

Representative MOORHEAD. If a corporation, whether it is regulated or unregulated, realizes that even if it doesn't expend the money, it will still get a refund, then the purpose of the investment credit has been undermined. We are then subsidizing—and I am not limiting myself to the utility industry—the least efficiently managed corporations, are we not?

Mr. NASSIKAS. I think your point is well taken. The difficulty is the whole regulatory structure has searched for years to try to find a way to reward the efficient corporations. What happens is the efficient corporation normally gets penalized under the regulatory structure and the least efficient one gets rewarded. I will tell you how. If a utility has an extremely competent management and earns a very fine rate of return on a very prudent investment, then rates are sometimes reduced or rate increases are shaved down, because that utility somehow manages to maintain its cash flow, its dividend payout, its fixed charges, its bond indenture requirements, etc. Now, the other utility that is inefficient, we can't very well, as regulators allow that utility, shall we say, to fall by the wayside and go into a receivership. The result is that there is pressure to increase rates, even though it is inefficient.

I agree with your principle. I agree with the principle. I wish I knew the answer.

Representative MOORHEAD. In this time of serious inflation and a significant recession, it seems that this little-noticed refunding provision should be eliminated for both the regulated and the nonregulated industries. Do we agree there, Mr. Chairman?

Mr. NASSIKAS. I would like, if I may, Mr. Moorhead, to think that over and see whether I would go that far and submit, if I may, a supplementary review of that very incisive question to you.[1]

Representative MOORHEAD. That will be fine. You appear to advocate economic policies to halt runaway wages, prices, and profits. Do you mean that we should return to some form of wage-price controls?

Mr. NASSIKAS. I think there should be standby controls. I haven't

[1] See response, beginning on p. 216.

quite reached the stage to say that it is necessary to have wage-and-price controls. I think we ought to give the economy a little more chance to see what economic forces can do without imposition of wage-and-price controls, but I do think that it might be desirable to have standby legislation enacted so that in the event immediate action is necessary, the power will be there through congressional authorization. That is basically my view.

The reason I put this in terms of economic policy was that I don't think we should immediately impose it. I know there have been hearings. I know it is a very argumentative point. I know there are strong feelings on both sides. I would like to see what our economy can do over the course of the next few months before we impose it.

I could change my mind quite drastically if our economic problems deepen.

Representative MOORHEAD. But in the field of energy conservation, you advocate some form of standby mandatory provisions?

Mr. NASSIKAS. I think mandatory standby provisions for conservation are necessary. There are some elusive aspects of energy conservation that sometimes don't meet the eye. I personally believe that if we deregulate new natural gas, for instance, it will assist energy conservation to the extent that the inevitably higher price will induce efficiencies and reduce demand for natural gas so that other fuels can take over in some applications. This is a way, I think, to conserve and reallocate our resources more effectively. I know that there are terrible economic problems involved in, shall we say, changing the American automobile industry to smaller automobiles, to smaller and lower horsepower and more efficiency. It seems to me that you can enact legislation that would either impose a tax on horsepower or would give some kind of an incentive to those who may use automobiles that can get 25 to 30 miles a gallon. I think our sights are very conservative when we say let's improve our efficiency of automobiles from an average of about 12 or 13 miles a gallon, to about 16 or 17 on average. I think that is terribly nearsighted. We have seen that the European automobile industry is suffering terribly also. France, England, Germany are all suffering, and so is Japan, but yet we see they make smaller cars. That, however, is the result, I think, of a worldwide economic problem, rather than the idea that the vehicles aren't sound. I think the smaller vehicle is sound. I think there ought to be some kind of tax legislation on this, and this would be excellent conservation.

Now, on insulation apart from mandatory requirements here, it seems to me the Michigan State Public Utilities Commission recently——

Representative MOORHEAD. I was going to ask you about that.

Mr. NASSIKAS. This is very innovative, Mr. Chairman. This is a very innovative move that they made whereby they have a differential rate structure between those who insulate and therefore conserve—and incidentally, that was natural gas, not electricity, but the same principle can apply to electricity, of course—and those who don't insulate, would have to pay a differential rate, which would be higher. There are some legal problems involved, and I don't want to say that this is an idea which we must readily adopt without further review. The question is whether, under statute, this kind of differential rate is legally supportable. I don't know, but I happen to think that it would be supportable in most States.

Representative MOORHEAD. One of the most controversial energy issues is the deregulation of natural gas.

Mr. NASSIKAS. Yes.

Representative MOORHEAD. On this question you state, and I think it is very carefully worded, that it should be under a "carefully monitored regulation with protective covenants for some consumers?"

Mr. NASSIKAS. Yes.

Representative MOORHEAD. That doesn't sound like deregulation as far as the natural gas producers are concerned.

Mr. NASSIKAS. It is not the concept that would be particularly popular with producers, that is, with all producers, at least. I think most producers would like to have deregulation of natural gas, period, or if you deregulate natural gas supplies, they would like that to be it with no reregulation, so to speak. Let me give you just two or three aspects of what I consider to be protective covenants for the public interest. I have said this before, and let me just summarize it.

In the first place, because world oil prices largely establish the commodity value on a British thermal unit basis of all energy supplies, especially incremental supplies of energy, it seems to me that it would be folly to deregulate natural gas without having some agency of government—and I urge the Federal Power Commission—to be granted authority to reregulate it, that is, to determine whether in specific markets, not simply broad, across-the-board markets, but in specific markets, whether the price has escalated to a stage which is simply resulting in excessive profits and no particular benefit to the consumer in the form of more gas.

The second thought in addition to reregulation, Mr. Chairman, is an excess profits tax. It is not really an excess profits tax, but that is what it is called. It is the same concept as the windfall profits tax for the oil producers that is before one of the committees of Congress. It has been urged by the administration for passage. I think a similar concept of excess profits or windfall profits tax should be proposed in the event there is gas deregulation. I just don't know what the tax rate should be, but above a certain level of gas price, there should be proposed a tax that gradually increases as the price of gas increases, with a credit given to the gas producers to the extent that they invest the excess revenues above the standard in further research, and exploration, and development for natural gas. That is a seocnd aspect.

Thirdly, we should, as a Commission, if we are given this authority to reregulate, be compelled to report to Congress on at least an annual basis or more frequently as to how the experiment is working.

Fourthly, the Justice Department and the Federal Trade Commission should be directed in such legislation to carry out their authority and responsibility with rigid antitrust enforcement.

What constitutes new gas is another question. We have defined "new gas" ourselves at the Federal Power Commission in a national ratemaking proceeding. Our rehearing order was issued at 10 o'clock this morning, so I can speak about it today.

We established back in June, in our initial opinion a definition of "new gas" which includes new dedications of gas to the interstate market and, as contracts expire, flowing gas would also be entitled to get the new gas price. There is to be a continual review of the price, at least on a biannual basis. We believe that what we have done is legal under the Natural Gas Act, but our experience has been any time we try anything that is innovative under this horrendous natural gas statute there are appeals to the courts. To be sure, we are usually sustained, but it takes 3 years to get up to the Supreme Court and get a final decision, so that is why we need legislation to deregulate gas, but on a controlled experimental basis.

Representative MOORHEAD. Mr. Chairman, just one last question. It seems to me that in a situation where additional capacity is required by an industry that is having difficulty raising money because of general economic conditions, rate regulations, delays, and so forth, that peak pricing is a logical answer. What is the reason for the resistance to the adoption of peakload pricing, and is there anything that the Federal Power Commission can do to encourage it? Do you need more legislation?

Mr. NASSIKAS. Well, let me say first that State commissions regulate over 90 percent of the industry's revenues and about 85 percent of the kilowatt-hours generated by the electric utility industry. While we have national responsibility through a uniform system of accounts and while our actions in the establishment of wholesale rates are watched very carefully, there is very little that we can do to compel anybody to adopt new rate designs. However, I believe that peak pricing or peak load responsibility, similar to the incremental pricing tariffs that were adopted in Wisconsin, and similar to the ones in Vermont, merit very deep and serious consideration. What I like about it is that the rate in the first place is directly associated with the cost of providing the service. If we have capacity installed so as to meet energy demand on a peak basis, the increment of plants, so to speak, and associated costs, is installed to provide that peak service. Therefore, those consumers who choose to utilize the plant in the form of electricity at peak, ought to bear the responsibility in rates to pay for those costs. Those who choose to utilize offpeak, ought to have a rate design which is less because the cost for use of those hours is less.

The economic theory of this kind of pricing is, I believe, very sound. We, of course, must act on the basis of an evidentiary record and anything we do on rate design would have to depend on the evidence in a case. I hasten to say we shouldn't simply wait for somebody to present evidence. Our staff has worked very diligently on this problem. Bob Uhler, who is next to me here, is one of our economists, and is chief of our Economic Studies Division, and Mr. Wald is our chief economist, and their staffs have done some very excellent work of this kind.

Representative MOORHEAD. You are in favor of it, not just for the larger commercial and industrial uses, but for all users. Is that correct?

Mr. NASSIKAS. Well, you see, rates are supposed to be (*a*) nondiscriminatory, as we know; (*b*) associated with costs; and (*c*) stable; and (*d*) they should have some historical continuity, or that is what the textbooks tell us anyway, and that is what we should do as regulators. Well, between theory and practice, it would be nice if we could have these across the board. I believe that there would be some exceptions made, because of associated costs.

I would prefer, nevertheless, equal rate treatment for all users in direct correlation with costs, but where the burden falls on those who can't afford to pay, you know, some relief has to be given through rates, through tax, or through some kind of a cash subsidy.

Representative MOORHEAD. Senator Proxmire, you may proceed.

Senator PROXMIRE. Mr. Chairman, how much of an increase have we had in natural gas prices in the last couple of years?

Mr. NASSIKAS. On flowing gas prices, when I came to the Commission the average price was about 15 to 17 cents. The average price of all gas at the wellhead today is somewhere in the area of 27 cents. That would be about a one-third increase in all gas. On new gas——

Senator PROXMIRE. Over what periods?

Mr. NASSIKAS. That is starting in August of 1969, which is my anniversary as Chairman. Now, for new gas, just on a generalized basis, it is about 24 cents, which was the price. It was less than that, I guess. It was in 1969, 18 cents, and then very shortly after I became Chairman, we had a series of rate cases where we went on average up to about 24 to 26 cents on new gas prices. Now, as of today, as of 10 o'clock this morning, the new gas price as defined in our national rate proceeding on rehearing, is 50 cents.

Senator PROXMIRE. So you are saying that the price of natural gas has gone up until it has almost tripled? It has gone up from 18 to 50 cents.

Now, you want to deregulate natural gas?

Mr. NASSIKAS. Yes, I do.

Senator PROXMIRE. How much farther would the price go up if you deregulated it?

Mr. NASSIKAS. Well, here again, it depends on the form of deregulation. If we have no controls, and we simply have deregulation of new gas with no authority of anybody to reimpose reregulation, then I believe that the price of new natural gas supplies will start approaching on a Btu equivalent basis the price of alternate supplies of oil, imports from Canada, of natural gas, imports of liquified natural gas from abroad, and so on. Basically speaking, Senator, for a dollar figure, it will be \$1.50 to \$2 Btu compared to a 50-cent price.

Senator PROXMIRE. So it would go up?

Mr. NASSIKAS. This is where I believe this would go on an uncontrolled basis.

Senator PROXMIRE. From 18 to 50 cents, and if decontrolled, it would go as high as \$1.50 or \$2; is that right?

Mr. NASSIKAS. Yes.

Senator PROXMIRE. How much new production have you obtained as a result of the increase from 18 to 50 cents?

Mr. NASSIKAS. There has not been any substantial——

Senator PROXMIRE. How much new discovery, or whatever?

Mr. NASSIKAS. Well, new discoveries I can't give off the top of my head.

Senator PROXMIRE. In other words, what kind of incentive for production is higher prices on the basis of evidence so far? What is the elasticity of supply when you increase the price?

Mr. NASSIKAS. Well, we find that there has been considerable elasticity of supply, but it defies the economists and certainly defies me as Chairman to indicate whether elasticity ranges as much as five tenths or whether it is closer to two tenths or three tenths in relation to an increase in price, but——

Senator PROXMIRE. If we decide to deregulate it will have tremendous inflationary consequences. You seem to feel that the inflationary effects will be limited. But these things have a way of spreading once you deregulate—new natural gas, even with protective covenants—because you have a situation where you get pressure to deregulate many other sectors across-the-board. We have calculated—and I am sure you would argue with these figures—that the typical natural gas user in Wisconsin, who pays about $250 or so a year for his gas now, would pay $1,000 if you deregulate it.

Mr. NASSIKAS. I haven't seen the figures.

Senator PROXMIRE. Well, it does depend on assumptions.

Mr. NASSIKAS. I haven't seen them, but I think that the impact of deregulation has been grossly exaggerated by both economists and perhaps by others.

Senator PROXMIRE. Well, you just confirmed the fact that as far as new natural gas is concerned—and I realize that there is a limited amount of new gas—you would have an explosion in price from 50 cents, which is already an enormous increase over what it was a few years ago, to $1.50 or $2.

Mr. NASSIKAS. What I said was that would be without reregulation, and without the protective covenants.

Senator PROXMIRE. Well, if you put in any reregulation provision, wouldn't that knock out whatever incentive for production that you have?

Mr. NASSIKAS. No.

Senator PROXMIRE. As I understand it, one major reason that you have a holdback in exploration is reaction to presidential statements. If you are a producer and you hear the President of the United States ask for deregulation of natural gas—and he didn't say new natural gas, but all natural gas, why should you go ahead and develop reserves which are going to be priced on a lower level? And that is what he said in his statement to Congress. He may not have meant that, but that is what he said, because I went over it carefully.

Mr. NASSIKAS. Senator Proxmire, all I can say is that any discussions I have had with his staff—and I have had numerous ones—that the concept is not deregulation of all gas; it is deregulation of new gas. There has been a bill before the Congress for upwards of 2 years to that effect, which I believe should have passed, and that had a reregulation provision in it, by the way, without the Federal Power Commission having reregulation authority, but rather giving it to the FEA. I prefer the Federal Power Commission to be given that authority. But the reason I advocate reregulation, Senator, is yes, it would have some counterproductive impact upon the exploration and development effort, but we can't have a perfect situation. We have to have some regulation and I believe that we can keep the price on a controlled basis far below $1.50 to $2 on reregulation and therefore the consumers would benefit by using a lower cost supply rather than going to alternate sources that are higher.

The National Energy Board of Canada recently increased gas prices from 32 cents flowing gas under contracts with U.S. importers in round figures to $1. This was done over a period of about 6 months. That is $1 across-the-board. The price of that gas being delivered to any point in Wisconsin, to any city in Wisconsin down to the Chicago market, which is a little bit more expensive, runs about $1.15 to $1.17 delivered to the city gate. We have gas being delivered from—and this is new gas being delivered and not just flowing gas—from—well, let us take flowing gas from the Gulf of Mexico to the same market at some place around 60 cents. Liquefied natural gas is being imported from abroad. Our first base load project, which we were able to certify, was at less than $1, and all pending applications we have range anywhere from $1.25 to $2 Mcf.

The only reason I point out these alternatives is that I believe the consumers of the United States, will benefit from gas deregulation and I think we are heading for a disaster if we don't deregulate natural gas. That is how strongly I feel. Otherwise I wouldn't advocate it.

Senator PROXMIRE. I think you will pardon me if I say that I think we are heading for disaster if we do. The disaster is very explicit and clear, and the figures seem to me to be overwhelming. At any rate, the bill before us defines new gas very broadly and allows renegotiation of old contracts. That means that all gas is likely to be deregulated soon if that bill should pass. Now, you are not testifing on that bill. You testified more broadly.

Can we get an estimate from you as to how much new natural gas would be included in your definition of carefully monitored deregulation of natural gas? What proportion of the gas that is sold annually would be covered here?

Mr. NASSIKAS. Well, we have some rough rules of thumb, but about 5 percent of the contracts expired annually. The eligibility for new gas prices for flowing gas supplies would range someplace around 5 percent plus and it may range as high as 10 percent, but this depends upon what increments of new gas supply——

Senator PROXMIRE. As you define it, 5 to 10 percent of the gas would be considered as new gas?

Mr. NASSIKAS. In round figures, Senator Proxmire, under the administration's bill, or Senator Buckley's bill—and there are other bills that have been presented too, most gas would be decontrolled in price.

Senator PROXMIRE. Since we are now in a very painful inflationary situation which is still our No. 1 economic problem, why not just set a reasonable permanent price, which would provide ample profits, and incentives for exploration with an inflation escalator?

Mr. NASSIKAS. That has been suggested.

Senator PROXMIRE. Why not do that instead of taking the lid off entirely where you have a monopolistic element?

Mr. NASSIKAS. That has been suggested. As soon as I finish testifying here I will go upstairs to the Senate Commerce hearings and try to answer that question.

The escalator idea is a fair idea. It does have to——

Senator PROXMIRE. Yes, and especially now. I can see under different circumstances when you didn't have the inflation problem that perhaps we could deregulate. But with energy being at the guts of our inflation problems, with the oil price being so high, with knowledge that you are going to have a price explosion and a terrific windfall paid to the companies by consumers, why isn't this the time to hold the lid on?

Mr. NASSIKAS. I don't see how the Congress can frankly establish a price and a ceiling—well, they can. They've got the legal power to do it. Congress can do it, but I don't think you should set a ceiling as has been advocated by the Senate Commerce Committee and I will testify to that before that committee today. Prices do change and costs do change, the profit position does change, and this does require very exhaustive analysis of what the real costs are and the relation between costs of oil and gas exploration. Costs are in themselves a very difficult type of thing to assess.

I don't think that natural gas prices should have a ceiling on them any more than I think that the Congress should across-the-board set up statutory prices on all energy. I mean, if it is applicable to gas, why not all energy? I just don't agree with it.

Senator PROXMIRE. But, we are in an extraordinary situation now with shortages of energy.

Mr. NASSIKAS. Yes.

Senator PROXMIRE. So you have the shortages to begin with and you have a price problem for the consumer who buys the heating plant for his other house. The consumer is not in a position to shift. Once he or she has made the commitment, that is it. The consumer is pretty much a victim of the charge at the moment. Under these circumstances, it seems to me that there is a very strong case for continuing the regulation we have had in the past. We have a very acute shortage and the clear knowledge that if we don't regulate, we will further aggravate inflation in the next few months. If we vote for complete deregulation of natural gas, we will aggravate the inflation further.

Mr. NASSIKAS. Well, in the first place, I don't think it will aggravate inflation further.

Senator PROXMIRE. You told us the price would go up.

Mr. NASSIKAS. I said if we don't have reregulation. I would like to repeat that for the record so that the record will be straight, Senator.

Senator PROXMIRE. What do you mean by reregulation? Is it a power of Congress to come in and reregulate?

Mr. NASSIKAS. No; the Federal Power Commission.

Senator PROXMIRE. You fellows are fallible. You almost have a majority of members of your Commission that want to deregulate natural gas.

Mr. NASSIKAS. That is true.

Senator PROXMIRE. I think you would be very reluctant to engage in reregulation.

Mr. NASSIKAS. Well, I can't speak for my colleagues. I would have no reluctance to regulate and if you will simply read my decisions, you will see that. I do have the support of the majority of the Commission. I do think you would find there is no reluctance on my part to reregulate and that is why I advocate it, nor would the majority of the Commission——

Senator PROXMIRE. Wouldn't you have excessive profits if you deregulate natural gas?

Don't the oil companies already have enormous profit increases three times above the level of a year ago?

Mr. NASSIKAS. Why, of course not. We just finished an 18-month rulemaking with an exhaustive examination of evidence and came out with a just and reasonable rate on the basis of the evidentiary record. Why, of course there aren't excessive profits, otherwise would we issue a decision like this? This will be appealed to the U.S. Supreme Court, and we usually get sustained by them.

Senator PROXMIRE. You mean to say that if you had deregulation with an explosion in price, that there wouldn't be a windfall profit in two ways: No. 1, you could get an annual profit and, No. 2, the value of reserves would go right up through the ceiling? We have calculated that deregulation would mean an increase in the value of reserves of about $130 billion, which is enough to make everybody in Racine and Kenosha, Wis., a millionaire. Every man, woman, and child.

Mr. NASSIKAS. You say it would be like Saudi Arabia and Kuwait? That is about the way it would work out.

Senator PROXMIRE. That is right. They would be living the way the oil people are living now.

Mr. NASSIKAS. But let me go back here. Under my concept, Senator, there would be no excessive profits. If we deregulate, there may be windfall profits so accordingly I suggested in my answer to Chairman Moorhead earlier in the day, and I have suggested this before other committees, that we should tie in any deregulation with an excess profits tax. I think you were here when I said that. I said, though, this is not truly an excess profits tax. In other words, if Congress were to pass a bill and were to set a price level of gas at—shall we say, simply to take a figure—50, 60 cents, or whatever, say 70 cents or say, forty cents, say whatever figure appears to be the figure to use, then any gas that is sold above that price, Senator, there would be a tax on it; there would be a credit against that tax to the extent that a producer could show that he reinvested those excess revenues in further exploration and development. This is very similar to the oil profits excess revenues tax that is pending before the other committee.

Senator PROXMIRE. Well, my time is up, Mr. Chairman.

Thank you very much. I want to thank you, Mr. Nassikas, for your very responsive replies. I think you can tell I strongly disagree with your position, but you put it very well.

Mr. NASSIKAS. Well, these issues are of paramount importance, and we can't have agreement on them. I respect your views, obviously, even though I don't agree with them.

Representative MOORHEAD. Well, we thank you very much, Mr. Chairman. I think your statement was very fine.

Mr. NASSIKAS. With your indulgence, Mr. Chairman, may I leave with your staff two or three copies of our latest national rate that came out at 10 o'clock this morning? It is a most interesting decision. It had four concurrences and dissents.

Representative MOORHEAD. Fine.

[The information referred to follows:]

[Federal Power Commission, News Release No. 20909, Dec. 4, 1974, Washington, D.C.]

DOCKET NO. R-389-B; NATIONAL GAS RATE; OPINION NO. 699-H

FPC INCREASES NATIONAL RATE FOR GAS PRODUCER SALES TO 50 CENTS ON REHEARING

The Federal Power Commission, following rehearing, today increased the single uniform national base rate for interstate natural gas sales by producers to 50 cents per thousand cubic feet, from the 42-cent base rate set in its original June 21, 1974 opinion.

The new rate applies to gas from wells commenced since January 1, 1973, and to new dedications of gas to interstate commerce since that date.

The Commission said the 50-cent rate, plus one-cent annual escalations, is sufficient to allow recovery of all costs plus a return of 15 percent. It said it believed the increased consumer cost attributable to higher wellhead prices is more than counterbalanced by the more probable assurance of continued service and expanded supplies.

Today's opinion was by Chairman John N. Nassikas. Commissioner Albert B. Brooke, Jr., concurred with a separate statement. Commissioner Rush Moody, Jr., dissented, and Commissioners William L. Springer and Don S. Smith dissented in part and concurred in part, each with a separate statement.

The Commission in a separate concurrent order (Docket No. RM74-15) instituted the first biennial review of its nationwide rate, covering calendar years 1975 and 1976.

Following issuance of the nationwide rate opinion last June 21, 37 petitions for rehearing were filed. Oral argument was held before the Commission last August 22 and 23. Many requests for rehearing simply reiterated contentions expressed previously, the Commission said, but all arguments were considered.

The FPC also modified its original opinion to permit all gas which initially qualifies for the nationwide rate to be priced at the rate established for each succeeding period. Otherwise, it said, the biennial review procedures will result in numerous vintages of gas each with a locked-in rate subject only to annual escalations which could discourage dedication of new gas supplies and cause further curtailments. This result is clearly contrary to the Commission's intent, the opinion said.

With the adjustment of all new (post-December 31, 1972) dedications of gas to the same rate, the burden of financing new gas supplies can be distributed between old and new customers and between historic and future demand, the FPC said. Additionally, such a policy over an extended period of time will result in a uniform base price for gas, which equates to the cost of replacing gas consumed. There is no rational basis for setting differing prices based on date of discovery, lease acquisition, contract, or well commencement or completion over an extended period, the FPC said.

Other modifications or clarifications of the original opinion are:

An increase from one to 1.5 cents per thousand cubic feet in the gathering allowance for the Permian Basin area, and prescription of gathering allowances for the Appalachian-Illinois, Other Southwest, Hugoton-Anadarko, Rocky Mountain, Southern Louisiana and Texas Gulf areas.

Producers will be allowed the nationwide rate where a renewal contract is entered into prior to the cutoff date if the original contracts expire by their own terms after that date and after expiration of the term of the original contract expiring before the cutoff date if such contracts expire after the cutoff date. The June 21 opinion allowed the national rate only where the prior contract expired after January 1, 1973, and the renewal contract was executed after that date.

Sales commenced under the Commission's optional certificate procedure, along with sales formerly made under emergency and limited-term certificates, qualify for the national rate, but on the express condition that no certificate has been issued under the optional procedure for the subject sale. The caveat is necessary to assure the integrity of the national rate structure and the optional procedure as separate components of a total rate design, the FPC said. The June 21 opinion did not include these sales.

Reservoirs discovered as the result of a well commenced on or after January 1, 1973, on acreage dedicated to interstate commerce prior to January 1, 1973, in such a manner that the sale would not otherwise come within the nationwide rate shall be entitled to that rate.

Rates for the Rocky Mountain area for contracts dated on or after October 1, 1968, where the sales do not qualify for the national rate, shall be 35 cents.

Pending resolution of the applicable standards for setting rates for small producers (Docket R–393), they may collect the national rate for qualifying sales, without refund obligation.

The first annual 1-cent escalation may be made January 1, 1975, and subsequent escalations on the first day of every year during the term of the contract.

The effective date of today's opinion is June 21, 1974.

The Commission left unchanged the following provisions of its original opinion:

Producers may pass on the total amount of increased taxes. The Btu adjustment authorized is consistent with the past FPC practice—the base rate is to be adjusted for production or severance taxes before the selling price is adjusted for Btu content.

Volumes of gas delivered in interstate commerce under the nationwide rate shall not also serve to discharge refund obligations or trigger contingent escalations.

The FPC rejected as contrary to established judicial precedent the assertions of the American Public Gas Association and Senator Abourezk that the FPC may not lawfully set rates by any procedures less strict than formal adjudicatory procedures. The present gas shortage and the need for vastly expanded exploration and development programs dictate that establishment of producer rates not be unduly delayed, the FPC said, and that administrative procedures such as rulemaking be used to prevent the rates from becoming stale before they are effective.

The Commission said in just over one year it was able to prescribe a single uniform national rate that will enable pipelines to more effectively compete with intrastate purchasers for new gas supplies. Had this case been conducted under traditional adjudication procedures, the FPC said, it is most likely that a final decision would not yet have been reached and the inadequate area rates would still govern interstate gas sales.

The FPC affirmed its use of the seven-year period 1966–72 to determine costs, rejecting the producers' contentions that productivity levels for the most recent 3 or 4 years demonstrate a definite downward trend which is not accounted for in the productivity findings of the original opinion. Quite the contrary is true, the Commission said: the 1966–72 period was adopted because it is most representative of future drilling efforts in light of recent productivity trends.

The FPC said it believed the substantial negative revisions of recent years should be partially discounted as non-recurring adjustments that will not be repeated in future years. Reserve additions for the most recent years are understated; increased Federal leasing in 1973 and 1974, along with a decline in negative revisions, will increase total reserve additions and result in improved productivity in the next several years, the Commission stated.

The producers alleged that the 15 percent rate of return is inadequate, and urged a return of 15 to 18 percent. The Commission said a 15 percent return is not unduly low in light of current financial conditions. While it is true that interest rates on short-term borrowing and long-term debt have increased significantly in the last two years, "it is not unreasonable to assume that these rates will decline over time," the FPC said.

In prescribing the 50-cent rate, the FPC said it carefully considered the impact of this rate on the cost paid by the consumer. To evaluate the impact of the rate on the price paid by the consumer, the FPC estimated the potential impact on consumers in four cities—Washington, D.C.; Boston; Chicago; and Los Angeles.

If new supplies at the national rate constitute a 10 percent increment of total supplies delivered in the first year and an additional 10 percent each following year, the FPC said, the increase nationwide attributable to the wellhead price would be 19.1 cents per thousand cubic feet by 1978. This would result in a total price of $1.8610 in Washington; $2.5610 in Boston; $1.3910 in Chicago; and $1.3510 in Los Angeles. The percent changes in prices paid by residential consumers in these markets compared with current prices would be, respectively, in 1978: 11.44, 8.06, 15.92, and 16.46, the FPC said.

The Commission noted that even with the increased cost of gas to the consumer, the price of gas will remain less than the price of alternate fuels in these same markets. "We believe that it is in the best interest of the American consumer to pay the higher price for gas which is necessary to induce expanded exploration and production efforts than it is for that same consumer to pay even higher prices for other fuels, if substitutable, the Commission declared.

Since more than half of energy fueling industrial economy is gas, augmentation of our gas supply will contribute to productivity, reduce unemployment, and assist in maintaining a viable economy, the FPC said. The consumer must pay the higher price if he is to obtain the volumes of gas required to satisfy his demands for a reliable, non-polluting energy source, it said.

The 50-cent rate, which applies to all natural gas producing areas in the lower 48 states, will apply to:

Sales made from wells commenced on or after January 1, 1973.

Sales made under contracts for gas not previously sold in interstate commerce, except under short-term and emergency sale procedures of the Commission's regulations, provided that no certificate for the sale has been issued under the optional procedure.

And sales made under contracts executed on or after January 1, 1973, where the sales formerly were made under permanent certificates of unlimited duration under contracts which have expired by their own terms since that date, or under contracts dated after that date where the prior contract expired by its own terms before January 1, 1973.

In its separate order instituting the first biennial review, the FPC did not propose a specific rate as the basis for modifying its regulations.

Comments on issues related to cost will be deferred until publication of 1973 cost data, the FPC said. However, it invited comments, to be filed by January 17, 1975, on all other issues which may affect establishment of a just and reasonable rate.

The Commission made all natural gas producers with sales of at least 10 billion cubic feet a year and all interstate pipelines respondents to the proceeding. Those wishing to participate in the proceeding should file a notice of intent by December 20, 1974. The Secretary will publish and serve on all parties a list of the participants by December 31, 1974.

At the present time the Commission said it believes there will be no need to hold a public conference or a trial-type adjudicatory hearing in this proceeding. Opportunity for filing of comments and responses fully protects the rights of the participants, the FPC said.

Commissioner Brooke said he concurs in today's order not because he is convinced of its adequacy to maximize the search for new interstate gas supplies, but because it represents a movement toward a more realistic economic method for determining the most effective level of producer rates. Despite serious misgivings, he said, he is compelled to concur because, in the public interest, the industries and ultimate consumers alike are entitled to an early answer, and because the Commission needs to proceed immediately with the 1975–76 biennium rate review.

While adjusting the "hitherto sacrosanct" Permian costing model by using discounted cash flow to assure a constant 15 percent return is a substantial improvement in ratemaking methodology, Commissioner Brooke said, it can only be viewed as a beginning step. The 50-cent prescribed rate is still "woefully inadequate" to enable the interstate pipelines to compete with any degree of effectiveness for new onshore supplies, he said. More weight should have been attached to non-cost factors which the courts have held to be lawfully permissable, when justified, Commissioner Brooke stated.

Converting the natural gas potential from remaining and often remote sources into deliverable supplies will require an enormous investment of capital. "Unless a sharp reversal of domestic natural gas supply trends occurs within the next couple of years, the national goal of self-sufficiency will be delayed;

curtailments and allocations will impose severe hardships on industry, and probably, on human needs customers; dependency on foreign suppliers will mount, and prices will increase. The ultimate loser, of course, will be the consumer—the person whom the Natural Gas Act was devised to protect," Commissioner Brooke declared.

Commissioner Moody dissented to the majority opinion, stating it will have "no more effect than the application of a bandaid to a severed jugular vein." While the opinion is superior to the original in some respects, he said, it perpetuates the fundamental error of setting a rate which will not return costs and which ignores noncost considerations.

The loser throughout is the interstate consumer, he said. The majority, he said, through insistence on historical average costs in setting rates, simultaneously forestalls procurement of new supplies already found and precludes drilling for the future supplies which might solve the shortage. A ratemaking process which penalizes frontier exploration becomes a national affront, Commissioner Moody declared.

The consumer will benefit from the larger number of offshore gas prospects that are made economically accessible by the higher rate, he said. In fact what the majority has done, for all practical purposes, is set a rate for new offshore federal domain gas, he said, for onshore gas will not move into interstate commerce under the rate set today.

The new rate will not greatly lessen the economic disruptions inherent in pipeline curtailments, he said. The current curtailments of an average of 15 percent are but a shadow of what lies ahead, Commissioner Moody said. The sharply accelerating deliverability decline which presages curtailment levels of 30 percent or more within the next five years clearly predicts economic chaos and a total breakdown of the FPC's rationing efforts, he said. Increased curtailment may well cause a higher rate to consumers, for less gas, than will an increase in the price paid to producers.

Commissioner Moody said he adheres to his view that a prediction of productivity which cannot be supported by the record renders the rate based on it unlawful. Productivity data for 1973 are significantly below the average figure used by the majority, yet the Commission irresponsibly chooses to ignore 1973 results, he said. 1973 was one of those expanded drilling years that the majority was looking to for new reserves, but 1973 drilling resulted in the lowest productivity on record, he pointed out. Secondly, the majority's conclusion that greater drilling efforts necessarily presage improved reserves is simplistic, he said.

Judicial direction is absolutely imperative if gas consumers are to be protected, Commissioner Moody concluded. The courts must immediately speak not only to what is permissible, but to what is required of the FPC in performing producer ratemaking functions. Without this direction, the FPC will do no more than follow the politically popular course of restricting rates to the level of estimated costs, Commissioner Moody said.

Commissioner Springer dissented to the majority's use of the DCF method of computing costs in today's opinion, and to its use of trending based on speculation as to the future, but concurred in the remainder of the opinion. The Commission in reaching its June 21 decision followed the cost-plus-fair-return method which has been consistently applied in area rate cases and approved by the courts innumerable times, he said. "I have no objection to examining new methods of regulation when the time is ripe," Commissioner Springer said, "but to do so at the end of an already decided case strikes me as unusual."

More importantly, he said, little consideration seems to have been given in this case to the new method, and this is unacceptable. The majority started off with a fixed 15 percent return on investment, he said. However, translated into a DCF methodology, computed roughly, the majority is now saying that producers are entitled to a 23 percent return, without an analytical examination of its need or effect, Commissioner Springer said. The time to begin any new pricing approach, he said, is January 1, 1975, in the first biennial review.

Commissioner Springer also said he would amend Opinion 699-B, which reinstated limited term and emergency certificates, to define what the FPC meant by the word "limited." As written, he stated, it would appear that limited terms may extend as long as 20 years. They should, in fact, be limited to the coming year or at most, to the immediate and following winter, or to 18-month periods, Commissioner Springer stated.

Commissioner Smith in his statement said he fully concurred in today's opinion except for the portion granting the nationwide rate to gas subject to expiring contracts. This policy is not a reasonable method of providing internal financing for producers, nor is it consistent with the public interest, he said.

The rate set purports to provide a fully adequate incentive for exploration, development and production of new supplies, Commissioner Smith said. If this is the case, then clearly no allowance of the new national rate for expiring contracts is justified, Commissioner Smith said. "If the new nationwide rate . . . is inadequate, then the remedy lies with adjustment of the nationwide rate level rather than in atoning for real or suspected inadequacies in that rate by granting the new price for the expiring contracts," he said.

The immediate cost to the consumer is not balanced by an assured or even demonstrably likely future benefit, Commissioner Smith continued. Between now and 1980 the cost to the consumer could reach $2.6 billion, not considering any price increases granted in future biennial reviews. "The granting of the price increase to flowing gas is highly discriminatory to new entrants in the industry who enter with an unwarranted competitive disadvantage," he said, and moreover is highly discriminatory among existing members of the industry.

He concurred that it is proper to provide that the prices established in the biennial reviews be applicable to gas first delivered during the preceding biennium. However, he stated, at some time, if the cost increases continue, the disparity between new prices and old prices will be large enough to outweigh the desirability of suppressing end term speculation. At that time, he said, only the new gas should be given the new price. In other words, vintaging by cost groupings ultimately will become necessary to preclude the exaction of excessive and unjustifiable economic rent from flowing gas, Commissioner Smith said.

The Commission should consider a plan allowing a producer to escalate the price of flowing gas sold to a given pipeline to the 50-cent rate to the extent of one, or possible two, thousand cubic feet of flowing gas for each thousand of new gas sold to pipeline buyers from onshore areas under a new contract each year. Such a plan might slow down the negative trend in onshore dedications to the interstate market and may be far more consistent with the public interest than the unconditional price increase in flowing gas granted by the majority, he said.

The awarding of the nationwide rate to expiring contracts sets the pricing system on a course that, if followed by future Commissions, would eliminate vintaging for all gas except that which is subject to life-of-lease or reservoir contract, he said. "I do not find substantial evidence that supports the nationwide, albeit gradual, discontinuance of vintaging . . . ," Commissioner Smith concluded.

FEDERAL POWER COMMISSION OPINION NO. 699–H

[18 C.F.R. Part 2§§2.56, 2.56a, 2.66)]

Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr.; Rush Moody, Jr.; William L. Springer; and Don S. Smith.

JUST AND REASONABLE NATURAL RATES FOR SALES OF NATURAL GAS FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973—DOCKET NO. R–389–B

OPINION AND ORDER ON REHEARING AFFIRMING IN PART AND MODIFYING IN PART OPINION NO. 699 AND GRANTING IN PART AND DENYING IN PART PETITIONS FOR REHEARING

(Issued December 4, 1974)

NASSIKAS, Chairman:

On June 21, 1974, the Commission issued its Opinion No. 699[1] determining and establishing a just and reasonable national rate structure for post-Decem-

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[1] F.P.C. (1974). Rehearing of Opinion No. 699 for purposes of further consideration was granted by the Commission's order of August 2, 1974, *amended*, F.P.C. (August 12, 1974).

ber 31, 1972 sales of natural gas in interstate commerce[2] Opinion No. 699–B,—F.P.C.—(September 9, 1974), reinstituted with modifications the emergency sales provisions (18 C.F.R. § 157.29) and the limited-term certification authority (18 C.F.R. § 2.70(b)(3)) which were terminated by Opinion No. 699.

Thirty-seven petitions for rehearing, reconsideration, and/or clarification of Opinion No. 699 were filed by natural gas producers, interstate pipelines, gas distributors, state agencies, a United States Senator, trade associations, and one industrial concern.[3] Twenty-three parties and groups of parties requested and presented oral argument before the Commission on August 22 and 23, 1974.[4]

Many of the petitions for rehearing simply reiterated contentions that were expressed in comments filed during the proceeding. We have, however, considered all arguments advanced by the applications, including those which were fully answered or otherwise disposed of in Opinion No. 699, and have made a number of modifications to the rate structure promulgated in Opinion No. 699.[5]

I. The use of rulemaking to establish just and reasonable national rates

Two parties to this proceeding, the American Public Gas Association (APGA) and United States Senator James G. Abourezk, assert in their applications for rehearing that the Commission may not lawfully establish just and reasonable rates by the utilization of any procedures less strict than the formal adjudicatory procedures prescribed by the Administrative Procedure Act.[6] These assertions are contrary to established judicial precedent[7] and are, accordingly, rejected.

APGA's contention that the Fifth Amendment to the Constitution requires the Commission to follow formal rulemaking proceedings in a ratemaking proceeding such as the subject one is erroneous and contrary to established precedent. There is no constitutional right to the formal procedures requested by APGA nor to any "particular form of procedure" which a party may desire. *National Labor Relations Board* v. *Mackay Radio & Telegraph Co.*, 304 U.S. 333, 351 (1938). "The requirements imposed by that [Fifth Amendment] guaranty [of due process] are not technical, nor in any particular form of procedure necessary." *Inland Empire District Council* v. *Millis*, 325 U.S. 697, 710 (1945); *Morgan* v. *United States*, 298 U.S. 468, 478, 481 (1936). Thus, since the Administrative Procedure Act "created safeguards even narrower than the constitutional ones,"[8] we must determine if the procedures followed herein comply with the requirements of the Natural Gas Act and the Administrative Procedure Act. If the constraints of the statutes are satisfied, then the constitutional inquiry is ended.

Both the United States Courts of Appeals for the District of Columbia Circuit and the Tenth Circuit have unequivocally held that the Federal Power Commission is not bound to observe the formal rulemaking procedures of sections 7 and 8 of the Administrative Procedure Act (5 U.S.C. §§556, 557) in establishing rates under the Natural Gas Act. *American Public Gas Association, et al.* v. *FPC*, 498 F.2d 718 (D.C. Cir. May 23, 1974); *Mobil Oil Corp.* v. *FPC*, 483 F.2d 1238, 1250–1251 (1973); *Phillips Petroleum Company* v. *FPC*,

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[2] Opinion No. 699–A, F.P.C. (August 2, 1974), modified the text of Opinion No. 699 and section 2.56(h)(1) of the regulations promulgated therein to provide (1) that sales formerly made under 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29, would be eligible for the prescribed national rate if a permanent sale of such gas was initiated on or after January 1, 1973, thereby eliminating the requirement that such sales be made pursuant to a contract executed on or after that date, and that (2) a renewal contract executed on or after January 1, 1973, qualified the continuing sale of such gas for the national rate regardless of the date of expiration of the former contract. See *infra* at 39–44.

[3] A list of those persons filing such petitions is attached as Appendix A.

[4] Persons presenting oral argument are listed in Appendix B.

[5] There are also a number of matters which have been clarified in response to questions pertaining to the rate structure and its application to natural gas producers, especially small producers.

[6] 60 Stat. 241–242 (1946); 5 U.S.C. §§556, 557 (1970).

[7] *United States* v. *Florida East Coast Ry., et al.*, 410 U.S. 224 (1973); *United States* v. *Allegheny-Ludlum Steel Corp.*, 406 U.S. 742 (1972); *American Public Gas Association, et al.* v. *FPC*, 498 F.2d 718 (D.C. Cir. May 23, 1974); *Mobil Oil Corp.* v. *FPC*, 483 F.2d 1238 (D.C. Cir. 1973); *Phillips Petroleum Co.* v. *FPC*, 475 F.2d 842 (10th Cir. 1973), *cert. denied*, 414 U.S. 1146 (January 14, 1974).

[8] *United States* v. *Morton Salt Company*, 338 U.S. 632, 644 (1950).

475 F.2d 842, 851–852 (10th Cir. 1973). There is no doubt that the two courts have disagreed over the theoretical issue whether the minimal requirements of Section 553 of the Administrative Procedure Act will suffice in a Commission ratemaking proceeding. That issue is not present in this proceeding, and APGA's assertion of "a split in the Circuits on this point" is misplaced.

In *Mobil* v. *FPC*, *supra*, there was no notice, no opportunity to submit data or comments with respect to the subject of rates, and the D.C. Circuit stated that "it appears probable that the FPC did not even comply with the minimal requirements of section 553." 483 F.2d 1238 at 1251 n. 39. The procedures in this case provided for the submission of two sets of initial and reply comments including such sworn testimony and data as the individual parties desired to bring to the Commission's attention, a public conference on the disputed issues of reserve additions and drilling footages, and oral argument upon Opinion Nos. 699 and 699–A. Thus, APGA cannot assert in good faith that it has been denied a "mechanism whereby adverse parties can test, criticize and illuminate the flaws in the evidentiary basis being advanced regarding a particular point," 483 F.2d 1238 at 1263.[9]

The *Mobil* case does not require the use of the formal rulemaking procedures under 5 U.S.C. §§556, 557 in this case as APGA so zealously asserts in its petition for rehearing.[10] Those procedures are required only where the underlying substantive statute compels that rules be made "on the record after opportunity for an agency hearing." 5 U.S.C. §553(c) (1970). The Supreme Court has held the absence of this language, while not absolutely controlling, is a strong indication that Congress did not intend that the formal procedures of sections 556 and 557 were to be mandated. *United States* v. *Florida East Coast Ry.*, 410 U.S. 224 (1973); *United States* v. *Allegheny-Ludlum Steel Corp.*, 406 U.S. 742 (1972).[11]

The "substantial evidence" requirement of the Natural Gas Act does not mandate that the formal procedures of sections 556 and 557 be followed in a ratemaking proceeding. The Court concluded in *Mobil* that "such complete adjudicatory procedures are not required." 483 F.2d 1238 at 1262.

Finally, the Commission's Rules of Practice and Procedure provide no support for APGA's position. Section 1.20(g) (18 C.F.R. §1.20(g)) merely provides for the "Presentation by the parties" when the Commission determines a formal hearing is required and initiates the same pursuant to Section 1.20(a) (18 C.F.R. §1.20(a)). Section 1.20(m) provides for procedures in rulemaking proceedings. 18 C.F.R. §1.20(m). Thus, it is clear that section 1.20 provides for the informal proceedings under 5 U.S.C. §553, the procedures followed in this proceeding, and the formal proceedings under 5 U.S.C. §§556, 557, without specifically requiring which of these procedures will be mandated in a given case.

In addition to the legal precedent supporting the establishment of national rates for sales of natural gas in interstate commerce in a rulemaking proceeding, there exists compelling public policy reasons for the utilization of such procedures in establishing rates on a national basis. That reason is the delay and uncertainty of the allowable rate levels, on the part of producers, pipelines, distributors, and the ultimate consumer, that accompanied the setting of rates on an area basis under traditional adjudicatory procedures. This delay and uncertainty reduces the commitment of capital to exploration and development efforts, compels the establishment of rates upon outdated records, and deprives consumers of incremental supplies of gas as a result of unrealistically low rates geared to out-moded historical costs. Clearly these results are not in the public interest and should be reduced to the extent possible under the Natural Gas Act consistent with providing all parties to the proceeding before the Commission a fair opportunity to present their views and cases to the Commission.

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[9] We note while APGA has consistently opposed the use of reserve additions as reported by the American Gas Association that no representative of APGA attended the public conference held in this proceeding. Nor did APGA avail itself of the opportunity to submit any testimony or data contradicting positions taken by adverse parties, but chose to rely solely upon statements of its counsel.

[10] 483 F.2d 1238 at 1250–51.

[11] These decisions and the *Phillips*, *Mobil*, and *APGA* decisions, *supra* n. 7 clearly show the error in Senator Abourezk's contention that we have "violated the congressional intent underlying the Natural Gas Act."

One need look no further than the recent Supreme Court decision in *Mobil Oil Corp., et al.* v. *FPC*,[12] which after 13 years finally concluded the proceedings to establish rates for the Southern Louisiana Area, to observe the delay and uncertainty that have accompanied the traditional adjudicatory method of setting area rates. This proceeding was commenced by the Commission on May 10, 1961,[13] and the Commission's opinion issued on September 25, 1968,[14] with rehearing denied on May 9, 1969.[15] The Court of Appeals for the Fifth Circuit affirmed the Commission's decision, but held that evidence on the supply of and demand for natural gas which had come into being after the Commission's decision required that the Commission have the power to reopen the case if it found a necessity for such action.[16] Upon receipt of the Fifth Circuit's mandate, the Commission consolidated the proceedings in Docket AR61–2 with the second round proceedings in Docket No. AR69–1, and provided for further hearings.[17] Following these hearings and a number of settlement conferences, the proposed settlement which became one of the major underpinnings of Opinion No. 598 was presented to the Commission on March 15, 1971. Briefs were filed with the Commission, and on July 16, 1971, Opinion No. 598 was issued.[18] This opinion completely revised the rates and refunds required by Opinion No. 546 and prescribed new rates and incentive refund work off and contingent escalation provisions. The Fifth Circuit affirmed the opinion in full on April 16, 1973,[19] and it was, in turn, finally affirmed by the Supreme Court on June 10, 1974.

To those who believe that the Southern Louisiana proceedings are simply an aberration caused by a unique set of circumstances, it is helpful to review the record of the other area rate proceedings. These proceedings also demonstrate an inordinate amount of delay where adjudicatory procedures were followed, and a much more rapid resolution of those proceedings in which rulemaking procedures were adopted.

The first Permian Basin proceeding commenced on December 23, 1960,[20] with the Commission's decision being rendered on August 5, 1965,[21] and affirmed by the Supreme Court in 1968.[22]

The second Permian proceeding was initiated on June 17, 1970,[23] and concluded by Opinion No. 662.[24] The petitions for review of this decision were withdrawn under Court orders of August 21 and 30, 1974.[25]

The Hugoton-Anadarko proceeding[26] was commenced on November 27, 1963, along with the Texas Gulf Coast proceeding.[27] Joint hearings were held on common issues and the cases severed for further hearings directed to issues related to the specific area. On September 18, 1970, the Commission approved a settlement in the Hugoton-Anadarko proceeding,[28] which was affirmed on July 31, 1972.[29]

The Commission finally rendered its decision in the Texas Gulf Coast proceeding on May 6, 1971.[30] This decision was reversed by the D.C. Circuit on

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[12] 42 U.S.L.W. 4842 (U.S. June 10, 1974).
[13] *Area Rate Proceeding, et al.* (*Southern Louisiana Area*), Docket No. AR61–2, 25 F.P.C. 942 (1961).
[14] 40 F.P.C. 530 (1968), *amended*, 41 F.P.C. 301 (1969).
[15] 41 F.P.C. 616, 617 (1969).
[16] *Austral Oil Co., et al.* v. *FPC*, 428 F.2d 407, *reh. denied*, 444 F.2d 125, *cert. denied sub nom. Municipal Distribution Group* v. *FPC*, 400 U.S. 950 (1970).
[17] *Area Rate Proceedings* (*Offshore Southern Louisiana, Federal Domain And Disputed Areas*), 41 F.P.C. 378 (1969). This proceeding was expanded to include a review of all Southern Louisiana rates by order of December 15, 1969. 42 F.P.C. 1110 (1969). The proceedings were consolidated by order of December 24, 1970. 44 F.P.C. 1638.
[18] 46 F.P.C. 86, *reh. denied*, 46 F.P.C. 633 (1971).
[19] *Placid Oil Co., et al.* v. *FPC*, 483 F.2d 880 (5th Cir. 1973).
[20] *Area Rate Proceeding, et al.*, 24 F.P.C. 1121 (1960).
[21] 34 F.P.C. 159, *reh. denied*, 34 F.P.C. 1068 (1965).
[22] *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).
[23] *Area Rate Proceeding* (*Permian Basin Area II*), 43 F.P.C. 899 (1970). The record in the Southern Louisiana proceedings were incorporated as part of the record of this proceeding in an effort to expedite a final resolution of the case. 43 F.P.C. at 901.
[24] 50 F.P.C. 390 (August 7, 1973), *reh. denied*, 50 F.P.C. 932 (September 28, 1973).
[25] *Chevron Oil Co., Western Division, et al.* (9th Cir., Nos. 73–2861, *et al.*, filed September 28, 1973).
[26] *Area Rate Proceeding, et al.* (*Hugoton-Anadarko Area*), 30 F.P.C. 1354 (1963).
[27] *Area Rate Proceeding, et al.* (*Texas Gulf Coast Area*), 30 F.P.C. 1354 (1963).
[28] 44 F.P.C. 761, *reh. denied*, 44 F.P.C. 1434 (1970).
[29] *California* v. *FPC*, 466 F.2d 974 (9th Cir. 1972).
[30] 45 F.P.C. 674, *reh. denied*, 46 F.P.C. 827 (1971).

August 24, 1973,[31] and that decision was vacated and remanded by the Supreme Court on June 17, 1974.[32]

The Other Southwest proceeding was commenced on February 28, 1967;[33] the Commission's decision was issued on October 29, 1971, and affirmed by the Fifth Circuit on June 8, 1973. Certiorari was denied by the Supreme Court on June 17, 1974.[34]

With the commencement on October 16, 1969,[35] of proceedings for the Appalachian and Illinois Basin area, the Commission initiated its use of rulemaking to establish area rates. This proceeding was concluded on October 2, 1970, with the issuance of Order No. 411,[36] which was not appealed.

Initial rates for post June 17, 1970, sales made in the Rocky Mountain area were established by Order No. 435, which was issued on July 15, 1971.[37] This order was affirmed on May 23, 1974.[38] Opinion No. 658 established just and reasonable rates for Rocky Mountain gas sold under contracts dated prior to October 1, 1968, and made the Order No. 435 rates applicable to contracts dated between October 1, 1968, and June 17, 1970.[39] The petitions for review of Opinion No. 658 were withdrawn by the petitioners on February 22, 1974.

The present gas shortage and the need for vastly expanded exploration and development programs to meet future demand dictates that the establishment of rates for "wellhead sales"[40] of natural gas in interstate commerce not be unduly delayed and that administrative procedures such as rulemaking be utilized to prevent the prescribed rates from becoming stale before they are effective. Moreover, the continually increasing competition from the unregulated intrastate market demands that the interstate market have the ability to respond as may be necessary to assure the maintenance of adequate natural gas service to the customers of the interstate pipelines.[41]

This procedural flexibility is available to this Commission through the rulemaking procedures that have been followed in the instant case. The Commission in slightly over one year from the commencement of the proceeding was able to prescribe a single uniform national rate that will enable interstate pipelines to more effectively compete with intrastate purchasers for new supplies of natural gas. Had this case been conducted pursuant to the traditional adjudication procedures, it is most likely that a final decision in this proceeding would not yet have been rendered, and the now superseded area rates, which had proven inadequate, would still govern interstate sales of natural gas. Thus, we are of the opinion that the expeditious resolution of this case has improved the regulatory climate and increased the attractiveness of the interstate market for

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[31] *Public Service Commission for the State of New York, et al.* v. *FPC*, 487 F.2d 1043 (1973).

[32] *Shell Oil Co.* v. *Public Service Commission of the State of New York*, 42 U.S.L.W. 3686 (U.S. June 17, 1974).

[33] 37 F.P.C. 400 (1967).

[34] *Area Rate Proceeding, et al. (Other Southwest Area)*, 46 F.P.C. 900 *reh. denied*, 47 F.P.C. 99 *affirmed sub nom., Shell Oil Co., et al.* v. *FPC*, 484 F.2d 469 (5th Cir. 1973), *cert. denied, sub nom., Mobil Oil Corp.* v. *F.P.C.* 42 U.S.L.W. 3688 (June 17, 1974).

[35] *Area Rates For The Appalachian And Illinois Basin Areas*, 34 *Fed. Reg.* 17341 (1969).

[36] 44 F.P.C. 1112, *amended*, Order No. 411–A, 44 F.P.C. 1334, *reh. denied*, Order No. 411–B, 44 F.P.C. 1487 (1970).

[37] *Initial Rates For Future Sales Of Natural Gas For All Areas*, 46 F.P.C. 68, *reh. denied*, 46 F.P.C. 620 (1971). These proceedings had commenced with a notice of rulemaking in Docket No. R–389 on June 17, 1970. 35 *Fed. Reg.* 10152; *see also*, 35 *Fed. Reg.* 11683 (1970).

[38] *American Public Gas Association, et al.* v. *FPC*, 498 F.2d 718 (D.C. Cir. May 23, 1974).

[39] *Area Rates For The Rocky Mountain Area*, 49 F.P.C. 924, *reh. denied*, 49 F.P.C. 1279 (1973), appeal dismissed *sub nom. Exxon Corporation* v. *FPC* (D.C. Cir. No. 73–1854, dismissed February 22, 1974). This proceeding had commenced July 15, 1971, with a notice of rulemaking, 46 F.P.C. 43, and the Commission's power to proceed under 5 U.S.C. §553 (1970) was affirmed in *Phillips Petroleum Co.* v. *FPC*, 475 F.2d 842 (1973), *cert. denied*, 414 U.S. 1146 (January 14, 1974).

[40] A "wellhead sale" is the sale of natural gas by a natural gas producer (including a pipeline affiliate) to another producer or an interstate pipeline. Pipeline production is also eligible for the rate established for "wellhead sales" pursuant to sections 2.56a and 2.66.

[41] While we have often stated our views that regulation of "wellhead sales" made in interstate commerce should be terminated as to new sales of natural gas subject to review by the FPC to prevent abuses should they occur, it is necessary to note that the Natural Gas Act requires that sales of natural gas for resale in interstate commerce must be made at rates that are "just and reasonable." *FPC* v. *Texaco Inc.*, 42 U.S.L.W. 4867 (U.S. June 10, 1974). Under such constraints, it has not been demonstrated by substantial evidence that intrastate prices are just and reasonable.

natural gas producers, especially in light of the modifications adopted in this opinion.

II. Rate design

A. COST FACTORS

The cost findings in Opinion No. 699 have been vociferously attacked by a number of parties to this proceeding as being too low[42] or too high.[43] For the reasons hereinafter set forth, we believe that the Commission should implement the traditional area rate costing methodology adopted in *Permian I*[44] and utilized since that time with the continuing approval of the Courts.[45] As a basis for prescribing just and reasonable rates, we adopt herein (1) a discounted cash flow (DCF) costing format to assure within reasonable limits that the rates found under the Permian methodology will produce a 15 percent rate of return over the life of the investment, and (2) drilling costs (both successful well and dry hole) trended by the use of least squares regression analysis to derive a range of reasonable costs.

We find that supplementary cost analysis necessary to assure that the rate allowed for new gas supplies adequately reflects the true cost of those supplies. We believe that the *Permian* methodology adjusted by applying a DCF analysis to produce a true yield of 15 percent over the life of the investment and further tested by the use of trended drilling costs will establish a more reliable foundation for a predictive just and reasonable rate than will the exclusive use of the *Permian* methodology standing alone. If the basis for prescribing just and reasonable rates is a more reliable evidentiary foundation so that producers may reasonably anticipate a 15 percent return on their investment, the rates established herein should meet our objective of encouraging increased future drilling efforts and the discovery of incremental gas supplies to avert ever deepening natural gas shortages. Without endorsing the arguments for or against DCF costing that have been made by the participants to this proceeding, we find that the DCF analysis[46] is necessary to make reasonably certain that the end result of a 15 percent return will be attained without the attrition inherent in the traditional *Permian* methodology and that the *Permian* methodology adjusted by the DCF analysis and supplemented by trended cost data is the most reliable basis for forecasting a reasonable rate structure.

Unlike a pipeline or an electric utility that may go into the bond market to raise money for the financing of major new projects, the typical natural gas producer depends upon internally generated funds and equity capital.[47] Because of the heavy reliance upon internally generated funds and equity capital, the producer is faced with the need to earn a return sufficient to maintain the attractiveness of its natural gas operations as compared to other alternative investments. If the natural gas producer does not earn a return on its natural gas operations which is equivalent to the return it can earn on alternative investments, it will invest its profits in those more attractive investments rather than in expanded natural gas operations. The DCF methodology is designed to evaluate the price required to yield a given rate of return over the life of the

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[42] Indicated Producer Respondents (Producers), all producer respondents filing individual comments, Columbia Gas System Companies and other interstate pipeline companies, the Interstate Natural Gas Association of America (INGAA), Associated Gas Distributors (AGD), United Distribution Companies (UDC), Southern California Gas Company, and General Motors Corporation. Other parties filed specific comments regarding costs for the Appalachian-Illinois Basin Area.

[43] The American Public Gas Association (APGA) and Senator James G. Abourezk.

[44] *Permian Basin Area Rate Proceeding*, 34 F.P.C. 159, (1965), *affirmed*, *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

[45] *Area Rate Proceeding (Permian Basin Area II)*, 50 F.P.C. 390, *reh. denied*, 50 F.P.C. 932 (1973), appeal dismissed *sub nom. Chevron Oil Co., Western Division, et al.* v. *FPC*, Nos. 73–2861, et al., 9th Cir., motions to withdraw appeals granted August 21 and 30, 1974; *Area Rate Proceeding, et al. (Southern Louisiana Area)*, 46 F.P.C. 86 (1971), *affirmed sub nom. Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974); *Area Rate Proceeding, et al. (Texas Gulf Coast Area)*, 45 F.P.C. 671 (1971), *reversed, Public Service Commission of the State of New York* v. *FPC*, 487 F.2d 1043 (D.C. Cir. 1973), *cert. granted, vacated* and *remanded, Shell Oil Co.* v. *Public Service Commission of the State of New York*, 42 U.S.L.W. 3686 (U.S. June 17, 1974).

[46] The basic DCF formats are set out in Appendix H to Opinion No. 699, F.P.C.

[47] The typical producer maintains approximately 76 percent of its capital structure as common equity with long-term debt accounting for 23 percent of the total capital and preferred stock accounting for under one percent. *See infra* at 33.

project. It recognizes the fact that there is a time value which can be placed upon capital and that cash flow must be at a level necessary to produce the anticipated return.

The DCF methodology reflects the cost of capital by allowing a return on all invested funds. The *Permian* costing format requires that dry hole and exploration expenditures be expensed and recovered through production. The *Permian* formula is explicable only by an assumption that the dry hole allowance in the price of existing production in each year is in the aggregate sufficient to pay for or "expense" the total dry hole costs for that year. This assumption may or may not have ever been correct for a given producer. However, such an assumption today is contrary to the public interest in two related respects. First, it provides a disincentive to existing producers to increase investment in exploration and development and to incur the concomitant dry hole expense. The perpetuation of such disincentives would frustrate the fundamental national goal of achieving a greater degree of energy self-sufficiency. Second, the assumption and, consequently, the methodology is discriminatory to new market entrants who have no flowing gas against which to "expense" the dry hole costs. Today, the price of each Mcf of new gas must fully reflect the cost of finding and producing that gas and we find that the *Permian* formula does not adequately achieve that goal. If the recovery of such funds is to be permitted only over the depletable life of the project, then a return must be allowed on these costs just as it is allowed for successful wells.

Several participants [48] urge that we correct the deficiency of no return on dry holes by adopting their proposed full cost accounting format. This full cost accounting methodology includes the dry hole costs as part of the net investment base upon which a return is computed under the *Permian* costing methodology, and would yield a rate level ranging from approximately 49 cents per Mcf to slightly over 56 cents per Mcf.[49] We decline to adopt their concepts of full cost accounting since it is our opinion that the DCF analysis correctly applies the principles of a return on dry hole costs and is a more reliable methodology for testing the validity of the prescribed just and reasonable rates. We will, therefore, adopt the DCF approach in testing the validity of the rates prescribed in this opinion rather than the suggested full cost accounting methodology.

While there may be certain informational gaps in the record as to the timing of pre-production expenditures and production of the gas discovered, we believe that the record as a whole permits us to make reasonable assumptions as to the timing of expenditures. We conclude that the timing pattern utilized in Case II of Appendix H to Opinion No. 699 [50] is the most reasonable assumption that may be made on the basis of this record. This pattern shows that the weighted average lead time from the expenditure of funds to the commencement of production is approximately 1.6 years which compares favorably with our conclusion in Opinion No. 699 that the average lead time was approximately 1.5 years.[51]

In utilizing the DCF analysis, we will retain the basic derivation of the various cost components adopted in Opinion No. 699 and other cases. We shall also continue to rely upon the statistical data sources utilized in the past cases for such sources are "well recognized and authoritative." Moreover, the comments of APGA and Senator Abourezk to the effect that we may not rely upon statistical data gathered and published by natural gas industry sources are truly misplaced in this proceeding for that issue has been resolved in favor of the Commission by the Courts. *Permian Basin Area Rate Case, supra*; Placid Oil Co., et al. v. *FPC*, 483 F.2d 880 (5th Cir. 1973), *affirmed, Mobil Oil Corp.* v. *FPC, supra*. Their comments regarding the net liquid credit have been considered. Again, taken in context, the value we assigned to the net liquid credit is reasonable in light of our utilization of drilling cost data for 1972 and an average productivity based upon the years 1966 through 1972, inclusive, as the basis for the cost computations and rate determinations.

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[48] Pennzoil Company, *et al.*, The Rodman Corporation, Tenneco Oil Company, and Texasgulf, Inc.

[49] See the exhibits presented in oral arguments by The Rodman Corporation, *et al.*, for the derivation of these costs.

[50] — F.P.C. —.

[51] — F.P.C. —, Opinion No. 699 at 71–72.

Rather than review each individual component of the detailed cost analysis set forth in Opinion No. 699, we shall concentrate upon the major variables such as drilling costs, productivity, rate of return, and the modifications required by the adoption of DCF costing to demonstrate the reasonableness of the costs and rates determined in this opinion.

With respect to the costs determined in this opinion, a range has been adopted which utilizes untrended 1972 cost figures as the low end of the range and trended drilling costs for the high end of the range. This range in conjunction with our cost findings based on *Permian* methodology tested by DCF analysis will provide a reasonably reliable estimation of the cost of new gas supplies, and it recognizes the fact that the drilling cost data available to the Commission is data for a past period which may not be truly representative of future costs.

1. Drilling costs

Both the Producers and UDC allege that the Commission erred in failing to trend drilling costs to allow for inflation since the 1972 drilling costs were reported by the Joint Association Survey (JAS). There is no error in the Commission's decision to use 1972 JAS drilling costs without trending to determine the low side of the cost range adopted herein. Such costs, in an era of rising costs provide a base line, but only a base line, upon which to determine rates. We have determined that the upper end of the cost range used to determine rates should be based upon drilling costs as trended by the application of regression analysis.

Trended drilling costs for 1973 were developed from a least squares analysis of actual per foot drilling costs for successful wells and dry holes for 1963 through 1972. This technique indicates that trended successful well cost per foot will be $29.83 and that trended dry hole cost per foot will be $16.69.

These trended costs will be used to develop the high side of a reasonable cost range because they are more likely to be representative of future periods than are drilling costs for a past year, even the most recent year.

2. Productivity

a. Reserve additions

Again, the Producers and UDC are the major parties objecting to our productivity computations.[52] These parties allege that we have committed error by using average productivity for the most recent seven-year period (1966–1972) to determine costs. Both the Producers and UDC support productivity findings in the range of 350 to 400 Mcf per foot drilled on the assumption that productivity levels for the most recent three or four years demonstrate a definite downward trend which is not accounted for in the productivity findings of Opinion No. 699. Quite the contrary is true for the most recent seven-year period. It was adopted as the basis upon which to compute productivity because we conclude that this period would be most representative of future drilling efforts in light of recent productivity trends.

Past area rate cases computed productivity factors upon the average for the longest time series available; that is, for the period 1946 to the most current year for which reserve additions and drilling footages were available. This policy was not completely unrealistic prior to 1968 when reserve additions first dropped to an extremely low level which has continued through 1973.[53] In part, the extremely low productivities since 1969 are due to net negative revisions being reported by the American Gas Association for those years. However, even after the exclusion of all revisions—negative or positive—the data still show a marked drop in reserve additions and productivity levels starting in 1968.[54]

It is to this decline that the Commission's attention must be directed for there are a number of questions regarding the decline which must be answered. Will the extremely low level of new additions experienced from 1968 through 1973 continue into the future? Are the productivity levels reported for 1968 through

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[52] A number of parties made specific objections to our inclusion of the Appalachian-Illinois Basin Area within the scope of the national rate and recommended the establishment of a separate rate based upon that area's unique characteristics. *See infra* at 65–66.

[53] See Table I. This table covers only the years 1966 through 1973 since reserve additions were not broken out into revisions, extensions, new field discoveries, and new reservoir discoveries in old fields prior to that year.

[54] Table I.

1973 indicative of future productivity levels?[55] Are there factors which may improve the level of new reserve additions and productivity in the future?

The expansion of gas-well drilling activity which began in 1972 and carried through the first six months of 1974 should increase the volume of new reserve additions in the near future. The reserve additions data for 1966 through 1972 show a significant drop for new field discoveries for the period 1968 through 1972 with extensions showing a decline for 1968 through 1973 over 1966 and 1967. New reservoir discoveries in old fields demonstrate a very erratic pattern for the entire period (1966–1973) with no discernable trend. Revisions show a precipitous drop after 1968 which accelerated in 1973. For 1966 to 1968, net revisions increased from a positive 3 Tcf [56] per year to a positive 4 Tcf per year. For 1969, net revisions were a negative 1.4 Tcf per year and this increased to a negative 1.9 Tcf for 1972. In 1973, net revisions increased to a negative 5.3 Tcf per year, nearly a three-fold increase. For present purposes, it is the trends in new field discoveries and new reservoir discoveries in old fields that are of the main interest.[57]

For the period 1968 through 1972, new field discoveries averaged approximately 1.4 Tcf per year compared to 2.8 Tcf per year for 1966 and 1967. This level increased to 2.0 Tcf in 1973 indicating that the expanded drilling programs were beginning to have an effect upon reserve additions. With the increased leasing of acreage in the offshore Federal domain starting in late 1972, it can be expected that the level of new field discoveries should increase significantly over the levels recorded for 1968 through 1972 in the 1973–1974 period. Thus, the use of the most recent three to four year period prior to 1973 would probably understate the level of new field discoveries for the near future.

The trend for new reservoir discoveries in old fields is no trend at all. The reported new volumes for this class of discoveries declined from 1966 through 1969 only to increase for two years before entering another declining mode. Given the trend for 1966 through 1973, it can be expected that the volumes attributable to this class of discoveries should again increase in 1974 or 1975. Here, the average for the eight year period (approximately 2.9 Tcf per year) should approximate or be somewhat less than the level that will be experienced in the near future.

Extensions demonstrate a discrete drop from a level of approximately 8 Tcf per year prior to 1968 to a level of approximately 5.3 Tcf after that year. Since 1973 extensions (5.3 Tcf) were substantially equivalent to the average for the previous five years, it would be easy to conclude that this level should continue for the near future. We would agree were it not for the increase in drilling activity since 1972. A careful analysis of the data on extensions results in the conclusion that this level may not be truly representative of future extensions. As new field discoveries increase the level of extensions will probably increase. New field discoveries increased in 1973 so it is probable that the level of extensions will increase in 1974 or 1975 unless new field discoveries again decline. Given the nature of the relationship between extensions and new fields and reservoirs, the present level of reported extensions is probably understated for the future and some allowance should be made for growth in this classification.

Revisions present the most difficult problem because it is extremely difficult to determine the relationship between revisions and drilling. Indeed, the AGA definition of revisions indicates to a certain extent that revisions are dependent upon production data in computing the magnitude of the revisions.

The drilling of additional wells in a reservoir not only delineates the productive area but also provides additional basic geological and engineering data. Estimates of porosity, interstitial water, pay thickness and other reservoir factors may be revised by new data. Analysis of the producing history of a reservoir, including production of oil, gas and water, and pressure performance results in more accurate concepts concerning the producing mechanism, recovery efficiency and the performance of the reservoir. The composite of this new and improved information will yield more precise estimates of the ultimate recoveries and remaining reserves and result in revisions to previous estimates. Changes in reserve estimates brought about [by] the application of cycling and

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[55] The productivity factor for 1973 is based upon preliminary drilling footage statistics and is subject to the possibility of modification when the final statistics are reported.

[56] Tcf stands for trillion cubic feet.

[57] See Table I.

other recovery techniques are included in the revision to reserves. Also, changes in reserves resulting from a reduction in the estimate of the proved area are included in revisions.

Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1973, Volume 28, June 1974, published jointly by the American Gas Association, the American Petroleum Institute, and the Canadian Petroleum Association. Thus, we must determine the extent to which revisions are the result of drilling and which are the result of additional production experience, as well as the date of discovery of the reservoirs to which revisions are attributable.[58]

Because the AGA reserve reports do not classify revisions by the year in which the reservoir was discovered, it is impossible to determine which revisions should be included in the total reserve additions for computing productivity because of the age of the underlying reservoir. It appears probable that at least a substantial portion of the large negative revisions which have been reported in recent years relate to older reservoirs which are being updated to account for production. The *National Gas Reserves Study* noted that in many of the Texas Gulf Coast fields "the A.G.A. seemingly was either still based on volumetric calculations or production curves which had not been updated." [59] Moreover, the AGA reported with respect to 1973 reserve additions the following information on negative revisions:

"Negative revisions of prior estimates were reported for both Texas and Louisiana. These downward adjustments are based primarily on data obtained from continuing production experience. These data indicate a greater loss of pressure with production than had been anticipated." [60]

These sources indicate to us that the substantial negative revisions of recent years should be partially discounted as non-recurring adjustments that will not be repeated in future years.

Having determined that the significant negative revisions of recent years will probably not be repeated in the future because of the probable nature of the revisions, we must determine whether net revisions will continue to be negative or positive and the most reasonable volumes which will be attributable to this class of reserve additions. The reported data for 1966 through 1973 are not very helpful. For 1968 through 1973, positive revisions increased from 4.3 Tcf in 1966 to 6.2 Tcf in 1968 and then declining to 1.4 Tcf in 1973. During this same period, negative revisions increased from 1.3 Tcf in 1966 to 6.8 Tcf in 1973, with the most significant increase coming in 1973 when negative revisions increased 3.4 Tcf over the levels reported the two previous years. See Table II.

It is significant in evaluating revisions that there have been two abrupt changes in the pattern of reported revisions. The first occurred in 1969 when positive revisions dropped from an average of 5.4 Tcf per year for the previous three years to a level of 1.4 Tcf. See Table II. The second change was the dramatic increase of negative revisions in 1973 over the prior years—this increase was in the order of 3.7 Tcf when compared to the three prior years. See Table II. Given these abrupt changes, it is probable that positive revisions will again increase and that the level of negative revisions will decrease. We are, however, unable to quantify the potential changes in the level of future revisions.

In summary, we conclude that reserve additions for the most recent years are understated due to negative revisions relating to the updating of reserve estimates for older reservoirs to reflect "continuing production experience," and a lower than normal level of new field and new reservoir discoveries resulting from decreased leasing in the offshore Federal domain in the late 1960's. The increased Federal leasing in 1973 and 1974 along with a decline in negative revisions will increase total reserve additions and result in improved productivity in the next several years.

Before leaving the subject of reserve additions and productivity, there is one final matter which deserves a reply. The Producers' contend that the Commission erred in its "statement . . . that the Producers did not submit any mathematical

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[58] The effect of revisions for the eight-year period (1966–1973) is shown in Table I to this opinion.
[59] FPC National Gas Survey, *National Gas Reserves Study* at 16, May 1973.
[60] American Gas Association News Release, March 28, 1974.

analysis of anticipated future productivity . . . is contrary to the record." [61] We note that Mr. Roe's own description of his study indicates that the study is limited to exploratory drilling, and does not include the effect of developmental drilling. Since Mr. Roe omitted an indispensable component in predicting future productivity, his study is not a credible mathematical model upon which the Commission may rely. Mr. Roe states:

"It should be carefully noted that this method has application only to the portion of annual reserve additions attributable to newly discovered fields and certain newly discovered reservoirs." [62]

Thus, it appears that Mr. Roe has concentrated his focus upon only part of the total picture. The qualifying statements in Mr. Roe's comments of May 7, 1974,[63] do not cure the deficiencies in Mr. Roe's presentation.[64] An analysis so limited cannot serve as the basis for computing anticipated future productivity and the establishment of just and reasonable national rates.

b. Drilling footages

The rather dramatic increase in gas well drilling footage for 1973[65] is also in part responsible for the decline in productivity for that year. The data for the first six months of 1974 indicates that 1974 footage may increase approximately 24.3 percent above 1973 levels[66] for a total of over 44,000,000 feet.

This increase in drilling footage will lower productivity unless reserve additions also increase. Since our evaluation of the various components of total reserve additions indicates that they should increase sufficiently to offset the increased drilling footage, there should be no material drop in productivity levels in the near future. Some particular producing areas may experience small productivity declines, but others should show increases as expanded drilling efforts begin to disclose new fields and reservoirs.

3. Rate of return and the rate base

The issues of the appropriate rate of return on the productive investment and the components to be included in the rate base are interrelated and will be considered together in this opinion on rehearing. Most of the contentions of the Producers and others challenging the rate of return allowed and the exclusion of dry hole costs from the rate base were fully answered in Opinion No. 699.[67] and need not be repeated here.

a. The rate of return

The Producers specifically, and others generally, allege that the 15 percent rate of return allowed by Opinion No. 699 is inadequate. It is urged that the rate is inadequate because of rising capital costs, inflation, and the natural gas shortage, and that rates of return of 15 to 18 percent after taxes on a discounted cash flow basis are required. The Producers also urge that they will not be permitted to earn the full 15 percent return allowed by the Commission. These contentions are erroneous as they fail to consider the fact that the rate allowed for non-associated gas is also allowed for associated and dissolved gas and for expiring

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[61] Application For Rehearing of Indicated Producer Respondents, at 22 n. 22.

[62] Response Of Indicated Producer Respondents To Notice Of Proposed Rulemaking And Order Prescribing Procedures, Appendix D at 2, May 16, 1973.

[63] Joint Comments Of Indicated Producer Respondents, Appendix I at 9–10.

[64] We note that Mr. Roe's analysis reaches conclusions similar to those reached by United Distribution Companies witness Ogden. *See* Comments Of United Distribution Companies In Response To Notice Issued March 21, 1974 (Separate Appendix Prepared By Willian J. Ogden), May 7, 1974. Mr. Ogden bases his studies upon productivity trends of the most recent years on the assumption that productivity will continue to decline in the future.

Mr. Ogden's comments attached to UDC's petition for rehearing which suggest that drilling costs must be adjusted in order to conform to the productivity level selected by the Commission have no basis in the evidence of this proceeding and are rejected.

[65] The increase of 1973 footage over 1972 footage is approximately 33.1 percent based upon preliminary footage data for 1973.

[66] Preliminary data for the first six months of 1973 and 1974:

Year:	*Footage drilled*
1973	15,936,742
1974	19,805,833

VIII *Quarterly Review of Drilling Statistics for the United States, Second Quarter, 1974*, No. 2, American Petroleum Institute (August 1974).

[67] F.P.C., Opinion No. 699 at 59–70.

contracts where a new contract is executed[68] thereby increasing the total return to natural gas producers selling gas in interstate commerce. Moreover, these contentions ignore the escalations provided by this opinion which further increase the return to the producer.[69] When all of these factors are evaluated, it cannot be said that the total return allowed by the Commission is not within a permissible "zone of reasonableness." [70]

We note that all of these factors are components of a total rate design and that it is impossible to single out any one component of the rate design as being unreasonable without considering the relationship of that component to the total. *Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974). When the rate of return allowed by Opinion No. 699 and this opinion are so considered, it cannot be said in good faith that the return allowed is insufficient or that the order "is unjust and unreasonable in its consequences." *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944); *see also, Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968); *Mobil Oil Corp.* v. *FPC, supra*, slip opinion at 19-23.

Before proceeding to an analysis of the appropriateness of a 15 percent rate of return, we are faced with the Producers' contention that they "are confronted with data not contained in the record." This data which comprised Appendix E of Opinion No. 699 set forth a study of the rates of return earned by various industrial groups in recent years. Such data is available to the public from widely recognized financial sources which this Commission may consider when it establishes rates. Thus, we find the Producers' contention pertaining to the extra-record nature of this data is meritless and it is rejected.

In general, the Producers' and UDC's main objections to the rate of return findings in Opinion No. 699 are the Commission's alleged failure to consider the evidence presented by the Producers' witnesses, Dr. Ezra Solomon and Kenneth E. Hill. This evidence was considered and evaluated by the Commission, but not adopted, and accorded the healthy skepticism that all evidence introduced by any party in a proceeding before the Commission receives before a decision is made. The FPC's function is to carefully weigh all evidence on all issues especially critical issues such as rate of return in order to protect the public interest. The Commission is, therefore, not required to treat as conclusive or controlling the evidence of any party. Such is the case of the evidence presented with respect to the rate of return in this case.

A fifteen percent rate of return is not unduly low in light of current financial conditions. While it is true that interest rates on short-term borrowing and long-term debt have increased significantly in the 1973–1974 period it is not unreasonable to assume that these rates will decline over time. We can to a certain extent discount these recent increases in evaluating the return allowed on long-term capital investments. The return on this investment must be a return that will attract capital for long-term investment. Because of the nature of the investments, there are different motivations which lead an investor to choose one over the other and it is impossible to equate the return on one with the return on the other. The best analysis that can be made is a comparison of the two. The long-term investment in gas exploration ventures which entail a certain degree of risk will necessarily have to provide a greater return than a short-term security that entails almost no risk. The dispute in this case is the difference that is required to make the long-term venture attractive to investors.

While historic levels of return for natural gas producers have been below the levels required to finance the necessary exploration programs, it has not been demonstrated by substantial evidence in the record of this proceeding that the allowed rate of return is inadequate. What has been demonstrated is the fact that the rates which had been determined in the prior area rate proceedings are too low and too far out of date. Had the Commission promptly determined, and then adequately reviewed rates in these earlier proceedings, as we provide in this decision, it is most probable that the revenues to the natural gas producers would have been adequate to expand exploration and production activities.

Having concluded that a base rate of return of 15 percent provides a sufficient incentive to attract capital to natural gas exploration and production ventures, it is necessary to consider the impact of allowing the rate provided for

[68] The contracts which are eligible for this rate are described *infra* at 40–44.
[69] The producers are further protected from the attrition of their return by the Biennial review provisions prescribed in this opinion. *See* 50–54 *infra*.
[70] *FPC* v. *Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942).

non-associated gas for associated and dissolved gas and for gas formerly sold under expiring contracts where a new contract has been executed. Associated and dissolved gas represents a lower cost product than non-associated gas since it is primarily a by-product of crude oil production. As such its costs are very likely to be considerably less than the cost of new non-associated gas supplies where the gas must bear the entire investment. Allowing the same price for this lower cost product as is allowed for the higher cost non-associated gas increases the overall rate of return on gas related activities while providing an additional incentive for increased oil exploration. The potential magnitude of this allowance may be ascertained when associated and dissolved gas additions have averaged approximately 1.8 Tcf per year for 1966–1972.[71]

Renewal contracts qualifying for the national rate[72] provide additional revenues and additional return to natural gas producers selling natural gas in interstate commerce. There are, of course, cases where the cost of continuing to produce additional quantities of gas may be greater than the price allowed by the expired contract or the higher national rate; however, the special relief provisions established in this proceeding[73] and under Section 2.76[74] furnish avenues of relief. In many cases, however, reservoirs continue to produce substantial quantities of gas after the original contract has expired at a cost which is significantly less than the estimated cost of new non-associated gas supplies. Again, the result is incremental return which is an addition to the base rate of return allowed for new gas supplies.

Finally, we note an error in Opinion No. 699 pertaining to the capital structure of a group of petroleum companies. The table in Opinion No. 699 was:

CAPITAL STRUCTURE—1972 [1]

	Millions	Capital ratios (percent)	Costs (percent)	Weighted component (percent)
Long-term debt	$21,858	23.35	6.25	1.46
Preferred stock	404	.43	6.00	.26
Common equity	71,352	76.22	17.42	13.28
Total	93,614	100.00		15.00

[1] Source: "Financial Analysis of a group of petroleum companies". A Chase Manhattan Bank study.

The table should have read:

CAPITAL STRUCTURE—1972

	Millions	Capital ratios (percent)	Costs (percent)	Weighted component (percent)
Long-term debt	$21,858	23.35	6.25	1.46
Preferred stock	404	.43	6.00	.03
Common equity	71,352	76.22	17.73	13.51
Total	93,614	100.00		15.00

If the cost of long-term debt and preferred stock is increased to 9 percent, the return on common equity becomes 16.87 percent.

b. The rate base

The main rate base issue is whether the Commission should adopt the principles of "full cost accounting"[75] thereby allowing a return on the dry hole or

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[71] Opinion No. 699 at 114, Table 4.

[72] The renewal contracts which qualify for the national rate are set forth at 40–44 *infra*.

[73] 18 C.F.R. §2.56a(g).

[74] 18 C.F.R. §2.76; *Policy With Respect To Sales Where Reduced Pressures, Need For Reconditioning, Deeper Drilling, Or Other Factors Make Further Production Uneconomical At Existing Prices*, Docket No. R-458, 49 F.P.C. 992, as amended, 49 F.P.C. 1325 (1973).

[75] The parties urging the adoption of a return on dry hole costs include the Producers, the Pennzoil Group, Tenneco Oil Company, The Rodman Corporation, Texasgulf, Inc., UDC, and General Motors.

"unsuccessful well" costs.[76] As previously mentioned,[77] we believe that it is better to adopt a DCF costing formula rather than graft the full cost accounting or return on dry hole cost concepts onto the *Permian* formula.

4. Summary of costs and rate determination

The costs derived from the DCF studies range from 47.82 cents per Mcf for the low end of the range to 51.46 cents per Mcf for the high end of the range.[78]

The low end of the range is based upon untrended 1972 drilling costs found in Opinion No. 699 at Appendix C, Schedule No. 1, Sheet 1 of 9, adjusted to reflect a 15% return on investment under a DCF analysis. *See* Appendix C to this opinion.[79]

The high end of the range is based upon trended drilling costs of $29.83 per foot for successful wells and $16.69 per foot for dry holes. The productivity is 485 Mcf per foot based upon our findings in Opinion No. 699 and the discussion of reserve additions and drilling footages *supra* at 17–27.

Based upon the foregoing cost range, we conclude that the rate determined in Opinion No. 699 should be increased from 42¢ per Mcf with escalations of 1.0 cents per Mcf per annum. We find that a reasonable rate may be prescribed ranging from 48 to 52 cents per Mcf and establish a just and reasonable rate of 50 cents per Mcf. This rate is sufficient to allow the recovery of all costs plus a DCF return of 15 percent when all factors are considered.

5. Federal income taxes

The Producers, the Pennzoil Group, The Rodman Corporation, Tenneco Oil Company, and Texasgulf, Inc., all allege that error was committed in the Commission's decision not to include a Federal Income Tax allowance in the national rate established in this proceeding.

We believe that the decision to reserve this issue for individual company proceedings is correct. As we stated in Opinion No. 699,[80] the complex nature of the Federal tax laws negate any simple calculation of a Federal tax liability and require consideration of the producer's tax returns in order to consider the timing relationships between investment expenditures, the expensing of intangible drilling costs,[81] and jurisdictional sales.[82]

Those parties questioning our treatment of the income tax issue cite the *City of Chicago* decision[83] as requiring the Commission to adopt their procedures for out adjustment for individual pipeline tax liabilities violated the "actual taxes paid" principles.[84] There is no reasoning in that discussion which compels the Commission to adopt the income tax computations set forth by participants to this proceeding just as the Court found no requirement that the Commission consider individual pipeline tax liabilities in pricing pipeline owned production.

6. Gathering allowances

In Opinion No. 699 (93–94), we provided for gathering allowances in the Hugoton-Anadarko, Permian Basin, and Rocky Mountain Areas. The Producers urge that we have erred in providing these gathering allowances by (i) reducing the gathering allowance for the Permian Basin from the 1.5 cents per Mcf provided in Opinion No. 662 (50 F.P.C. 462 (1973)) to 1.0 cents per Mcf and (ii) failing to recognize the gathering allowances provided in the Appalachian-Illinois Basin, Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas. The Producers further urge that the 1.0 cents per Mcf gathering allowance prescribed for the "Other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area be increased to 1.5 cents per Mcf as provided in *Permian II*. We agree that the first two points raised by the Producers dictate corrective

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[76] F.P.C., Opinion No. 699 at 64 n. 85.

[77] *Supra* at 13–18.

[78] An annual escalation of 1.0 cents per Mcf is allowed for in both cases consistent with the escalation provided in Opinion No. 699.

[79] These costs were used in Case III of Appendix H to Opinion No. 699 to compute a DCF return of 12.65%.

[80] F.P.C., slip opinion at 73–76.

[81] Int. Rev. Code of 1954, §263(c) ; Treas. Regs. §1.612–4.

[82] Such an investigation would be concerned solely with expenses, deductions, and revenues associated with and incurred or generated in connection with jurisdictional sales. — F.P.C. —, Opinion No. 699 at 74.

[83] *City of Chicago* v. *FPC*, 458 F.2d 731 at 756 (1971), *cert. denied*, 405 U.S. 1074 (1972).

[84] *See* 458 F.2d 731 at 754–757.

action; however, there is no data or evidence in this record which dictate an increase in the previously determined gathering allowances for the "other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area.

The reduction in the gathering allowance for the Permian Basin from 1.5 cents per Mcf to 1.0 cents per Mcf was an inadvertent error and section 2.56(h)(4) will be revised accordingly.

Unlike the gathering allowances for the Hugoton-Anadarko, Permian Basin, and Rocky Mountain Areas which were stated separately, the gathering allowances for the Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas were made a part of the base rates. Furthermore, a deduction equal to the applicable gathering allowance was provided for if the gas was delivered to the purchaser closer to the wellhead than a central point in the field, the tailgate of a processing plant, an offshore platform, or a point on the purchaser's pipeline in the Other Southwest,[85] Southern Louisiana,[86] and Texas Gulf Coast[87] Areas. Thus, in these areas we will prescribe gathering allowances to be added to the base national rate only if deliveries are made no closer to the wellhead than the points described above. The amount of the gathering allowance provided for these areas will be the amount prescribed in the applicable area rate opinion.

The gathering allowance for the Appalachian-Illinois Basin Area was included in the base area rates and made applicable to all sales.[88] The same treatment for gathering in the Appalachian-Illinois Basin Areas will be provided in this proceeding.

The producers also allege that the gathering allowances for the "Other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area should be increased from 1.0 cents per Mcf to 1.5 cents per Mcf because of "increasing costs, necessity for additional compression on older systems and inflation itself." We have exhaustively reviewed the record of this proceeding for evidence which would support such a claim, and we find none. In such cases, the mere allegations of counsel are not sufficient to support the increase and the claim is accordingly rejected.

7. *Btu adjustment*

The Producers and United Gas Pipe Line Company (United) have questioned the procedures for computing the Btu adjustment that were promulgated in Opinion No. 699.

United objects to the computation of the Btu adjustment after the applicable severance or production tax has been added to the base national rate because it must now reimburse 100 percent of any such taxes rather than 87.5 percent as required by this Commission's orders for the Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas and because the producers have no incentive to object to new increases in such taxes.

We believe that United's position should be rejected. There is no rational reason why natural gas producers who elect to sell their gas in interstate commerce pursuant to Opinion No. 699, as amended by this Opinion, should be penalized because a state legislature determines that the best interest of the state dictates an increase in that state's production or severance tax. In past opinions, natural gas producers were allowed to pass on a fraction of the increased taxes, generally 87.5 percent, and bear the remainder. While there may be a sustainable basis for such a practice in the past, we are unable to conclude that natural gas producers should not be permitted to pass on the total amount of such increases. The Btu adjustment authorized in this proceeding is consistent with the past practices of this commission which indicate that the base rate is to be adjusted for production or severance taxes before the selling price is adjusted for Btu content.

Both United and the Producers seek clarification of the basis upon which the Btu adjustment is to be made. United requests the Commission to clarify whether "the Btu will be measured on a 'saturated' or 'dry' basis depending upon the terms of each individual contract." The Producers argue that the

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[85] 46 F.P.C. 900, 919, 924 (1971).
[86] 46 F.P.C. 86, 132, 143 (1971).
[87] 45 F.P.C. 674, 704, 719 (1971).
[88] 44 F.P.C. 1112, 1122–1123 (1970). This allowance applies to all sales whether or not the gas is gathered.

heating content (Btu) "of the gas should be adjusted for the water vapor content in the gas as it is delivered." In *Texaco, Inc.*, 33 F.P.C. 1228 (1965), the Commission determined that Btu adjustments should be made on a saturated basis. 33 F.P.C. 1228 at 1236–1237. This is the basis which was utilized in the area rate proceedings, and it is the basis that will be adopted in this proceeding. Section 2.56(h)(2) will be modified accordingly to reflect Ordering Paragraph (D) of Opinion No. 464. 33 F.P.C. 1228 at 1238.

B. SCOPE OF THE ORDER

A number of parties have questioned the scope of the order in this proceeding with respect to the eligibility requirements for the three classes of natural gas sales which the Commission has determined qualify for the rate prescribed by this decision. In Opinion No. 699–A,[89] the language of Opinion No. 690[90] and Section 2.56(h)(1) was amended to provide the following eligibility requirements for those qualifying classes of gas supplies other than gas supplies which qualify under a "wells commenced" standard:

(2) sales initiated on or after January 1, 1973 for the sale of natural gas in interstate commerce where such gas has not previously been sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29, or (3) sales made pursuant to contracts executed on or after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which [have] expired by their own terms.

Most of the questions concerning the scope of Opinion 699 pertain to the interrelationship between Opinion 699 and Opinion 639.[91] Other questions relate to sales commenced under the optional procedure pursuant to 18 C.F.R. 2.75(n) where the optional certificate is not accepted or issued and to which wells commenced on or after January 1, 1973, qualify for the national rate. Pipeline production and newly discovered reservoirs are discussed *infra* at 46–50.

1. Renewal contracts

By Opinion No. 639, *supra* n.91, the Commission announced its policy of eliminating vintaging by contract date through the vehicle of allowing the renewal contract to receive the new gas rate upon expiration of the term of the previous contract pursuant to the provisions of the prior contract. The Commission has applied this policy in several situations as to the timing of the renewal contract and the expiration of the prior contract as the Producers point out.

Opinion 699 allowed the national rate only to those situations where the prior contract expired on or after January 1, 1973, and the renewal contract was executed on or after that same date. Opinion No. 699–A, *supra*, amended this language to include all renewal contracts executed on or after January 1, 1973, regardless of the date of expiration of the term of the primary contract.

The amended language of Opinion No. 699–A meets one of the two situations advanced by the Producers as not being covered by Opinion No. 699.[92] However, the other situation where a contract is entered into prior to the cutoff date and prior to the expiration of the term of the contract does not fall within the language of Opinion No. 699. We believe that renewal contracts falling within this classification should be allowed the national rate after the expiration of the term of the previous contract and not before that date. *Mobil Oil Corp. (Operator), et al.*, 49 F.P.C. 239 (1973).

In making such modifications, we shall continue to require that the renewal contract be executed on or after January 1, 1973, or, in the alternative, that the

[89] — F.P.C. — (August 2, 1974).
[90] — F.P.C. —, Opinion No. 699 at 1.
[91] 48 F.P.C. 1299 (1972).
[92] These two situations were (a) where the term of the prior contract expired prior to January 1, 1973, and a new contract was executed on or after that date and (b) where the term of the prior contract expired on or after January 1, 1973, and a renewal contract was executed prior to that date. The Commission held that the new gas rate applied to such sales in *Southern Union Production Company*, 50 F.P.C. 217 (1973), and *Mobil Oil Corporation (Operator), et al.*, 49 F.P.C. 239 (1973), respectively. In *Mobil Oil Corporation (Operator), et al.*, 49 F.P.C. at 239, we held the new price would not become effective until the term of the prior contract expired.

term of the primary contract has expired on or after that date, whether or not the renewal contract was executed before that date.[93] While such requirements may not extend the national rate to all sales that come within the literal terms of Opinion No. 639, they are reasonable limitations upon the scope of the national rate.

Superior Oil Company's suggestion that the national rate be allowed for sales of natural gas where the term of the prior contract has expired and the seller and purchaser have been unable to agree upon a renewal contract must be rejected. The principles of vintaging expressed in Opinion No. 639 as adopted in Opinion No. 699 presumes that purchaser and seller of gas which is the subject of an expired contract will execute a renewal contract that is beneficial to both.

The automatic allowance of the national rate upon expiration of the formerly effective contract would release the seller from any obligation to bargain in good faith with the purchaser for a new contract, and such a situation we believe to be contrary to the public interest.[94] In many cases, the purchasing pipeline may desire a *quid pro quo* from the selling producer in the form of additional acreage dedication, exploration and development activity on the previously dedicated acreage, or other similar activities that could result in the dedication of additional new gas supplies to the interstate market. Such concessions by the seller will certainly not be made if the price is allowed to increase to the national rate automatically without the requirement of a renewal contract. Since such concessions are in the public interest because of the need for additional gas supplies which can be dedicated to interstate pipelines, it would be untenable to force the purchasing pipeline to pay the increased rate without the opportunity to obtain additional benefits for itself and its customers.

Finally, we find no merit to Superior's contention, made at the oral argument in this proceeding, that the requirement of a renewal contract violates section 4(b) of the Natural Gas Act.[95] No evidence was made a part of the record of this proceeding which would support such an argument, and, in the absence of such evidence, we are constrained to reject the argument. In so disposing of Superior's argument, we do not intend to imply that there may not be situations where the refusal of the purchaser to bargain in good faith for a renewal contract would not provide a basis for Commission action to remedy the situation.

On September 6, 1974, Austral Oil Company Incorporated (Austral) filed a motion for reconsideration of Opinion No. 699[96] and 699–A[97] and proposed that the promulgated regulations be amended to provide that deliveries which have been made for a period of twenty years or more under a contract for the life of the lease are entitled to the national rate.[98] Austral did not raise this issue before Opinion No. 699 was issued by filing comments and its motion presents no evidence which would make our consideration of the issue appropriate upon rehearing. According, Austral's motion is denied without prejudice to Austral submitting such comments on the issue as it desires to enter into the

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[93] In Opinion No. 639, we spoke in terms of the prior contracts being those executed prior to October 8, 1969, and renewal contracts as those contracts which replace the pre-October 8, 1969, contracts. October 7, 1969, was the division date for vintaging purposes in the Appalachian and Illinois Basin areas. 49 F.P.C. 1299 at 1310. Thus, since we establish a new vintaging date of January 1, 1973, in this proceeding, it follows that this date should be utilized in a rational manner to determine which renewal contracts are eligible for the national rate.

[94] Likewise, there is an obligation upon the purchaser of such gas to bargain in good faith with the seller to formulate a renewal contract.

[95] Section 4(b) provides:

"No natural gas company shall . . . (1) make or grant any undue preference or advantage . . . or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, . . . or any other respect, either as between localities or as between classes of service." 52 Stat. 821, 822 (1938); 15 U.S.C. §717c(6) (1970).

[96] — F.P.C. —.

[97] — F.P.C. —.

[98] This filing was not made within 30 days of either Opinion No. 699 or 699–A as required by statute, and it must, therefore be treated as a motion for reconsideration rather than an application for rehearing. *See Appalachian Power Company*, Project No. 2317, Opinion No. 698–A at 2–5. F.P.C. (1974).

record of the proceeding instituted today to establish rates for the 1975–1976 biennium.[99]

2. Optional procedure deliveries

A number of parties have requested that we include sales commenced pursuant to Section 2.75n[1] of the optional procedure[2] with sales formerly made pursuant to the provisions of the emergency sales and limited term certification procedures[3] as qualifying for the national rate. This position has merit, and we shall adopt it on the express condition that no certificate has been issued under the optional procedure for the subject sale.

The caveat which we adopt is necessary to assure the integrity of the national rate structure and the optional procedure as separate components of a total rate design. The caveat guarantees that a producer who may have been issued an optional certificate at a rate which is lower than the national rate will not later seek a new certificate at the national rate because it provides greater benefits than the rate under the optional certificate.

3. Newly discovered reservoirs on committed acreage

In Opinion No. 567,[4] the Commission determined that newly discovered reservoirs located on acreage previously dedicated to interstate commerce would be entitled to the price which otherwise be applicable to a contract dated as of the date of discovery except for the fact that the subject acreage had been dedicated under a contract in an earlier vintaging period. The Producers contend that we clarify Opinion No. 699 "by providing that Section 2.56 . . . be appropriately amended to provide for the application and interaction of the principles of Opinion 567 and that of the National Rate. . . ." We believe that this contention is well taken and it will be adopted as a modification of Section 2.56a (formerly Section 2.56(h)).

We shall provide that reservoirs, discovered on or after January 1, 1973, as the result of a well commenced on or after January 1, 1973, on acreage dedicated to interstate commerce in such a manner that the sale would not otherwise come within the provisions of subsection 2.56a(a)(1), shall be entitled to the rate determined in this proceeding. In most situations, we believe that reservoirs discovered on or after January 1, 1973, on acreage committed under acreage dedications to interstate commerce prior to January 1, 1973, would come within the provisions of the first two classes of sales enumerated under Section 2.56a(a)(1). There may, however, be cases where such would not be the case, and we will accordingly provide that these reservoirs will be entitled to the rate prescribed herein.

The producer seeking the national rate for production from newly discovered reservoirs on committed acreage shall make the filings required by 18 C.F.R. §2.56(f)(2). This subsection has been incorporated as part of the national rate structure in Section 2.56a.

4. Pipeline production

By Opinion No. 568,[5] the Commission determined that natural gas produced from leases acquired after October 7, 1969, by a pipeline or a pipeline affiliate would be priced at the area rate applicable to gas of the vintage which corresponds to the date that the first well on the lease is completed.[6] We believe that

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[99] *See National Rates For Jurisdictional Sales Of Natural Gas Dedicated To Interstate Commerce On Or After January 1, 1973, For The Period January 1, 1975, To December 31, 1976*, Docket No. RM75–14, "Order Instituting National Rate Proceeding," F.P.C. (December 4, 1974).

[1] 18 C.F.R. §2.75n.

[2] *Optional Procedure For Certificating New Producer Sales of Natural Gas*, 48 F.P.C. 218, *amended* and *reh. denied*, 48 F.P.C. 477, *reh. denied*, 48 F.P.C. 1002 (1972), *affirmed, John E. Moss, et al.* v. *FPC*, Nos. 72–1837, D.C. Cir., August 15, 1974 (Reversed as to pregranted abandonment, section 2.75e).

[3] 18 C.F.R. §§2.68, 2.70, 157.22, and 157.29.

[4] *Hugoton-Anadarko Area Rate Proceeding (Committed Acreage), et al.*, Docket No. AR64–1 (Severed Issue), *et al.*, 42 F.P.C. 726 *reh. denied*, 42 F.P.C. 1062 (1969), clarified, 43 F.P.C. 222 (1970).

[5] *Pipeline Production Area Rate Proceeding (Phase I)*, 42 F.P.C. 738, *as amended*, 42 F.P.C. 1089 (1972), *affirmed, City of Chicago* v. *F.P.C.*, 147 U.S. App. D.C. 312, 458 F.2d 731 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972).

[6] 42 F.P.C. 738 at 754, 18 C.F.R. §2.66(a).

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the General Policy Statement relating to that decision should be amended by adding a new subsection (c) which will provide that natural gas which comes within one of the classes enumerated in new Section 2.56a(a)(2) shall be entitled to the rate set forth in that section regardless of the date the lease was acquired by a pipeline or pipeline affiliate.

During oral argument, it was noted that the language of Section 2.66(a) may pose a vintaging problem for new drilling efforts by pipelines on post-October 7, 1969 leases.[7] While the vintaging policy announced in Opinion No. 567 is not referred to in Section 2.66, it is referred to in the text of Opinion No. 568,[8] and we believe that it should be applied to leases owned by pipelines and pipeline affiliates. Thus, new reservoirs discovered on such leases will be entitled to the national rate applicable to wells commenced and new dedications to interstate commerce of the date of discovery.

In applying the uniform national rate to all qualifying production from leases owned by pipelines or pipeline affiliates, regardless of the date of acquisition of the lease, we are not unmindful of the fact that Opinion No. 568 reserves the rate treatment of pipeline production from leases acquired prior to October 8, 1969, to Phase II of the *Pipeline Production Area Rate Proceeding*,[9] and that Phase II was terminated by our order of June 14, 1972, reserving the appropriate rate treatment for such leases to company by company rate proceedings.[10]

In the order terminating Phase II, the Commission stated:

"We believe the search for consumer protection through proper incentives and proper price can best be achieved by consideration of individual pipeline production and cost patterns, and company by company determination of pricing for production of leases acquired prior to October 7, 1969." 47 F.P.C. 1523.

At the time these principles were announced, the applicable area rate was dependent upon date of contract dedicating the production to the interstate market[11] rather than date of well commencement as established in this proceeding. The change to vintaging by a well commencement date rather than date of contract should be applied to pipelines and pipeline affiliates as well as producers. There is no difference between a well commenced on or after January 1, 1973, by a pipeline or pipeline affiliate on a lease acquired prior to October 7, 1969, and a similar well commenced on a lease acquired after that date just as there is no difference between a well commenced by a pipeline or pipeline affiliate and a similar well commenced by a producer. Since it is the time at which a well is drilled that ultimately results in the greater portion of the cost of the gas supply rather than the costs incurred at the time the lease was acquired, the artificial distinction of lease acquisition date promulgated in Opinion No. 568 should be eliminated from the national rate structure. The existing natural gas shortage requires the best efforts of all persons whether producer, pipeline, or pipeline affiliate to explore for and develop new supplies of gas to satisfy existing unfulfilled demands. These best efforts should not be hindered simply because of the date the lease was acquired,[12] and it is, therefore, in the public interest to allow the national rate for pipeline or pipeline affiliate production which qualifies under Section 2.56a(a)(2)[13] regardless of the date on which the subject lease was acquired.

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[7] The specific language reads: ". . . gas . . . will be priced . . . at the just and reasonable area rate applicable to gas of a vintage corresponding to the date of completion of the first well on the lease. . . ." 18 C.F.R. §2.66(a).

[8] 42 F.P.C. 738 at 752.

[9] 35 F.P.C. 497 (1966). *See* also *Area Rate Proceeding, et al (Hugoton-Anadarko Area)*, 31 F.P.C. 1595 (1964).

[10] 47 F.P.C. 1523 (1972).

[11] Newly discovered reservoirs located on previously committed acreage were subject to the price determined by date of discovery rather than date of contract. *See* n. 103, *supra*.

[12] Whether production dedicated to the interstate market prior to January 1, 1973, from pipeline or pipeline affiliate leases acquired on or before October 7, 1969, should receive the rate ultimately determined for pre-January 1, 1973, gas supplies is a matter to be resolved in Docket No. R-478.

[13] See *infra* 75–76, Ordering Paragraph (A). We believe that this clarification answers the questions posed by the New Mexico Commission since gas produced from post-December 31 1972, wells will qualify for the national rate whether drilled by a pipeline or a producer.

C. THE BIENNIAL REVIEW

As a result of our further consideration of the biennial review procedures set forth in Opinion No. 699 [14] and the comments with respect to that portion of the opinion filed in petitions for rehearing, we have concluded that those portions of Opinion No. 699 must be modified to permit all gas which initially qualifies for the rate prescribed by Opinion No. 699 to be priced at the rate established for each succeeding period.

The biennial review procedures established by Opinion No. 699 will result in the promulgation of numerous vintages of gas each with a locked-in rate subject only to annual escalations. These pricing policies, if implemented, could discourage the dedication of new gas supplies to the interstate market and cause further increases in the curtailment of service by most of the major interstate pipelines.[15] Such results are clearly contrary to the Commission's responsibility under the Natural Gas Act to assure the maintenance of adequate supplies of natural gas at the lowest reasonable price.[16] The continued decline in discoveries of new gas supplies and increased curtailment by the pipelines will increase the costs paid by the consumer for the gas itself at the wellhead and for the transportation service performed by the pipeline. These increases will ultimately produce prices that are not just and reasonable, but excessive, and service which is totally inadequate.

We are of the opinion, however, that adjusting the rate established in Opinion No. 699 to the rate levels established in succeeding biennial reviews will encourage the dedication of additional gas supplies to the interstate market at the lowest total cost to the consumer while protecting the financial integrity of the producer. Whether these adjustments will be upward or downward will, of course, depend upon whether costs and the other pertinent rate design factors increase or decrease.[17] It is precisely these variables that will be considered in the biennial reviews to determine rates for future periods, and these continuing reviews will allow the Commission to monitor changes in the economy which have a bearing upon the price of gas and the need for capital to finance the necessary exploration, development, and production activities. With the adjustment of all new (post-December 31, 1972) dedications of gas to the same rate, the burden of financing new gas supplies can be distributed between old and new customers and between historic and future demand.

The adjustment of all rates for post-December 31, 1972, dedications to the newly established rate will also over an extended period of time result in a uniform base price for gas sold in interstate commerce, which equates to the cost of replacing the unit of gas consumed. This uniform price will constitute a recognition of the fact that gas is a consumable, irreplaceable commodity and not a service which can be renewed by man.[18] Thus, there is no rational basis for setting differing price levels based upon date of discovery, lease acquisition, contract, or well commencement or completion over an extended period of time.[19] Our application of the principles enunciated in Opinion No. 639 in

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[14] F.P.C., Opinion No. 699 at 101–102.

[15] *See* Opinion No. 699, F.P.C., slip opinion at 31–35.

[16] *Mobil Oil Corp.* v. *F.P.C.*, 42 U.S.L.W. 4842 (U.S. June 10, 1974). *See Atlantic Refining Co., et al.* v. *Public Service Commission of New York*, 360 U.S. 378 at 388 (1959), citing §7(c) of the Natural Gas Act as enacted, 52 Stat. 825. "The 1942 amendments to §7, 57 Stat. 83, were not intended to change this declaration of purposes." 360 U.S. 378, 388, n. 7.

[17] The evidence of record in this proceeding indicates that drilling and other costs have trended upward since the early 1960's and that productivity has risen and fallen during the same period. The increasing severe inflation in the economy all but guarantees that costs and, therefore, rates will not decrease in the near future. More importantly, this inflation will require a continuing review not only of the cost factors, but also the rate of return allowed as just and reasonable.

[18] *See F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591 at 647 (1944) (Jackson, J., concurring); *Placid Oil Co.* v. *F.P.C.*, 483 F.2d 880 (1973).

[19] For the immediate future, we believe the distinction drawn between gas which qualifies for the rate established in this proceeding and the rate which qualifies under Docket No. R–478 should be maintained to avoid potentially severe and harmful economic dislocations due to significantly increased rates. These dislocations will be slowly eliminated by the vintaging policies adopted in this opinion and Opinion No. 639. *Area Rates for the Appalachian and Illinois Basin Areas*, 48 F.P.C. 1299 at 1309–1310 (1972), *affirmed sub nom., Shell Oil Co., et al.* v. *F.P.C.*, 491 F.2d 82 (5th Cir. 1974).

this proceeding permits the rate allowed for gas sold pursuant to older contracts to rise as those contracts terminate by their own terms adding to the revenues and, in turn, capital available to those entities which will explore for and develop new natural gas supplies for the interstate market.

As we previously noted, the magnitude of the drilling effort that will be required to elicit the supply of gas necessary to fulfill reasonable future demands [20] calls for massive capital commitment.[21] Much of the capital for exploration, development, and production comes from gas production revenues, and, therefore, we find it appropriate to adjust the rate determined in this proceeding to whatever level the biennial review demonstrates to be just and reasonable as one means of generating the necessary capital. Because we fully expect future rates to be higher, the adjustment of the rates established in this opinion to those higher levels which are above the costs found to be reasonable in this opinion will generate additional revenues above costs which can be reinvested to expand exploration and production activities.[22] Without such increases in the rate allowed for post-December 31, 1972, gas supplies, we do not believe that it will be possible for natural gas producers to generate the internal funds necessary to undertake the massive expansions of present exploration and development programs which we find to be essential if a level of annual reserve additions approximating 37 trillion cubic feet is to be remotely approached and sustained.[23]

D. THE IMPACT ON THE CONSUMER

In prescribing a just and reasonable national base rate of 50 cents per Mcf, we have carefully considered the impact of this rate upon the cost paid by the consumer for natural gas. In order to evaluate the impact of this rate upon the price paid by the consumer, we have estimated the potential impact on the price charged the residential gas consumer in four widely dispersed metropolitan areas of the United States.

Assumptions must be made in order to estimate the potential impact of increased prices for new supplies of natural gas. In the following table, it is assumed that new gas supplies including supplies sold pursuant to renegotiated contracts will account for five (5) percent of the supplies delivered in the first year and will increase by an additional 5 percent of the total volumes delivered each following year. It is further assumed that the volumes delivered to these four markets will remain constant over the next five years. To the extent that increasing curtailments reduce the volumes of gas available at the prices paid during the calendar year 1973, the estimated increases shown in Part IV of the table will be somewhat greater. The prices shown in the table reflect the annual escalation of 1.0 cents per Mcf, a seven percent production tax, a Btu content of 1,030 Btu per cubic foot, and a gathering allowance of 1.0 cents per Mcf. The prices are computed as provided in Appendix D to Opinion No. 699. The prices do not reflect any adjustments that may result from the biennial review prescribed by this opinion.

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[20] F.P.C., Opinion No. 699 at 22–24.

[21] The total amount of capital required will be further increased by the continued rise in costs which may be expected for several years into the future.

[22] Rates will not be allowed to increase indefinitely without some discernible increase in the level of monies committed to exploration and development programs and the volumes of new gas supplies dedicated to interstate pipelines under long-term contracts.

[23] Whether such a level of physical findings can be achieved and sustained is a question that only experience can provide an answer for; however, it is certain that this level will never be attained unless the funds are available to finance exploration, drilling, developmental, and production activities. *See* Opinion No. 699 at 23.

POTENTIAL IMPACT OF 50-CENT BASE RATE, AS ADJUSTED, ON RESIDENTIAL BILLS IN SELECTED MARKETS ASSUMING 5-PERCENT INCREMENTS

Line No.	Classification	Residential market areas: Washington, D.C.	Boston, Mass.	Chicago, Ill.	Los Angeles, Calif.
1	I. Average cost of natural gas service for calendar 1973 in dollars per thousand cubic feet:[1]	1.67	2.37	1.20	1.16
	II. Increase in the cost of natural gas assuming 5 percent increments of gas purchased at base rate, as adjusted:[2]				
2	(a) 5 percent (1974) 56.38 cents	.0169	.0169	.0169	.0169
3	(b) 10 percent (1975) 57.48 cents	.0349	.0349	.0349	.0349
4	(c) 15 percent (1976) 58.59 cents	.0540	.0540	.0540	.0540
5	(d) 20 percent (1977) 59.70 cents	.0742	.0742	.0742	.0742
6	(e) 25 percent (1978) 60.81 cents	.0955	.0955	.0955	.0955
	III. Adjusted average cost of natural gas dollars per thousand cubic feet:				
7	(a) 1974	1.6869	2.3869	1.2169	1.1769
8	(b) 1975	1.7049	2.4049	1.2349	1.1949
9	(c) 1976	1.7240	2.4240	1.2540	1.2140
10	(d) 1977	1.7442	2.4442	1.2742	1.2342
11	(e) 1978	1.7655	2.4655	1.2955	1.2555
	IV. Percent change as result of 50-cent price for each increment percent:				
12	(a) 5	1.01	.71	1.41	1.46
13	(b) 10	2.09	1.47	2.91	3.01
14	(c) 15	3.23	2.28	4.50	4.66
15	(d) 20	4.44	3.13	6.18	6.40
16	(e) 25	5.72	4.03	7.96	8.23

[1] Source: AGA's "Gas Facts for 1973."
[2] Volumes based upon form 11 data for 12 mo ending December 1973 and assumes constant level of total volumes.

If new supplies at the national rate constitute a 10 percent increment of the total supplies delivered in the first year and an additional 10 percent increment each following year, the increase attributable to the wellhead price of gas paid by consumers in residential market areas would be 19.1 cents per Mcf by 1978. This would result, by 1978, in a total price per Mcf of $1.8610 in Washington, D.C., $2.5610 in Boston, Mass., $1.3910 in Chicago, Ill., and $1.3510 in Los Angeles, Calif. The percent changes in the prices paid by residential consumers in these same markets would be:

Year	Washington, D.C.	Boston, Mass.	Chicago, Ill.	Los Angeles, Calif.
1974	2.02	1.42	2.82	2.92
1978	11.44	8.06	15.92	16.46

Furthermore, 50 percent of the total volumes of gas being sold in interstate commerce will be priced at the national rate by 1978 if the annual increments are 10 percent.

Referring to the table and accompanying text, it appears that the increases in the average residential price will range between 0.71 percent and 1.46 percent in the first year and between 4.03 percent and 8.23 percent after five years if total volumes of gas priced at the national rate account for an annual increment of 5 percent of the total volumes delivered that year. If the annual increment is 10 percent then the increases will range from 1.42 percent to 2.92 percent for the first year and from 8.06 percent to 16.46 percent after five years. The increases will tend to be smaller, percentage-wise, as the distance from the major producing areas to the consumer market increases, but the dollar impact will be determined by the relative importance of new gas supplies in each market's total gas supply. In addition, of course, there will be an indirect impact upon consumers to the extent that increased gas prices paid by commercial and industrial customers are passed on in the form of higher prices for goods and services. As noted below, however, the increased availability of gas supplies at the national rate will, in many instances, enable commercial and industrial customers to continue their use of gas rather than converting to a higher cost alternative fuel. In these cases, the increased price for gas might well prove to be deflationary rather than inflationary.

In evaluating the overall public interest, we must consider the benefits to the consumer of an incremental supply of gas to provide reliable gas service compared to the consumer detriment if natural gas supply is reduced. The increased consumer cost attributable to higher wellhead gas prices is more than counterbalanced by the more probable assurance of continued service. It should be noted that even with the increased cost of gas to the consumer as a result of this decision the price paid for gas will remain less than the price of alternate fuels in these same markets. These customers will, of course, be confronted with even higher energy costs when demand is referred to other higher-priced alternate fuels because an adequate and reliable supply of gas is not available. We believe that it is in the best interest of the American consumer to pay the higher price for gas which is necessary to induce expanded exploration and production efforts than it is for that same consumer to pay even higher prices for other fuels, if substitutable. To the extent that incremental supplies of gas will be made available to consumers at less cost than alternate fuels, inflationary pressures will be diminished and we will more effectively allocate and utilize our energy resources.

Since more than 50% of the energy fueling our industrial economy is natural gas,[24] which in many applications cannot be efficiently displaced by other fuels, the augmentation of our natural gas supply will contribute to our productivity, will reduce unemployment, and will assist in maintaining a viable economy.[25]

Future supplies of gas required to replace the volumes being consumed today as well as increase the deliverable volumes to meet anticipated future demands will come from greater depths onshore and from both greater well depths and water depths offshore. These supplies will not be discovered and produced at yesterday's prices so it is important that we establish a price that will encourage the development of those higher cost supplies. The consumer must pay this price if he is to obtain the volumes of gas required to satisfy his demands for a reliable, non-polluting energy source.

In establishing a base rate of 50¢ per Mcf as the national rate and reinstating emergency and limited-term procedures in Opinion No. 699-B, we are carrying out our responsibility as a Commission to see that consumers receive adequate and reliable gas service at reasonable prices. In *Hope*[26] the Supreme Court expressed the essential doctrines stating that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks,"[27] and that the Natural Gas Act was "To protect consumers against exploitation at the hands of natural gas companies."[28]

III. Deeper drilling and deeper offshore water depths

The Producers and GHK Company and Gasanadarko, Ltd., object to the Commission's failure to provide an additional allowance for deeper drilling efforts and all drilling efforts in deeper offshore water depths. With one exception, these objections are fully answered in Opinion No. 699.[29]

There remains the question of how prospective drilling efforts which will explore depths greater than 15,000 feet below the surface and which will take place

[24] Federal Power Commission, Natural Gas Survey, Volume I, Chapter 6, "Total Energy Supply and Demand," at pages 40 and 93 (Preliminary Draft).
[25] Employment Act of 1946, 60 Stat. 23 (1946), 15 U.S.C. §1021 (1970).
[26] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[27] 320 U.S. at 603.
[28] 320 U.S. at 610.
[29] The Producers' request for clarification of section 2.56(h)(6)(ii) is noted and section 2.56a(g)(2) [formerly 2.56(h)(6)(ii)] has been amended to reflect the language of Opinion No. 699 at 132–133.

in water depths greater than 250 feet may be certificated so as to provide finance the drilling effort.[30] Such ventures may be certificated under the optional procedure.[31] This clarification will remove any uncertainty that may have been caused by the *Continental* order.

It is our intention to initiate the proceedings required to determine the appropriate allowances for drilling efforts to depths greater than 15,000 feet and all drilling efforts in water depths greater than 250 feet as part of the biennial review proceedings that have been initiated in Docket No. RM75-14, which is being issued concurrently with this opinion. This will avoid a proliferation of separate proceedings pertaining to similar issues.

IV. Contingent escalations and refund credits

The Producers and others argue that the Commission has violated the Natural Gas Act by imposing a reparations order and destroyed the prior area rate opinions in ordering that reserves dedicated pursuant to Opinion No. 699 may not also qualify to discharge refund obligations or trigger contingent escalations. *See* Opinion No. 699 at 99–100, 104–105, and section 2.56(h)(ii) [now section 2.56a(i)]. The Producers argue that these incentive provisions were part of the flowing gas rate which is not under consideration in this proceeding and not part of the new gas rate.

These arguments misconstrue the rationale underlying the adoption of these incentive provisions. The refund credit and contingent escalation provisions were adopted in four area rate cases[32] as part of an overall rate structure designed to elicit new supplies of gas for the interstate market. As such they were components in a total rate design which included a determination of both a new gas rate and a flowing gas rate.[33] These rates were balanced with the incentive provisions to insure that new supplies of gas would be available to the consumer at the lowest reasonable price.

In this proceeding, we have established a uniform national rate for post-December 31, 1972 dedications to the interstate market which is designed to elicit new supplies of gas to the interstate market. This rate structure was not contemplated when the earlier area rate opinions were adopted,[34] and it is not reasonable to allow new dedications of gas to the interstate market to receive the price allowed by this decision and, at the same time, discharge refund obligations or trigger escalation provisions pursuant to other opinions of this Commission. We realize that it would be highly advantageous to many natural gas producers to sell new gas supplies at the national rate and have those same volumes discharge existing refunds or trigger contingent escalations, but we find nothing which would indicate that it is in the public interest to allow natural gas producers the benefits of the area rate opinions while avoiding the burdens of those opinions. The allowance of rates prescribed in this opinion plus either the contingent escalation or the refund credit for new gas supplies would constitute an apostasy of the Commission's area rate opinions which

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[30] In *Continental Oil Company, et al.*, Docket Nos. CI74-526, *et al.*, F.P.C. (July 25, 1974), we held that prospective drilling efforts do not qualify for special relief under the various area rate opinions.

[31] 18 C.F.R. §2.75; *Optional Procedure For Certificating New Producer Sales Of Natural Gas*, Docket No. 441, Order No. 455, 48 F.P.C. 218 (1972), as amended by Order No. 455-A, 48 F.P.C. 477 (1972), *affirmed sub nom. John E. Moss, et al.* v. *FPC*, Nos. 72-1837, *et al.* (D.C. Cir. August 15, 1974).

[32] *See* Opinion No. 699 at 99 n. 133, F.P.C.

[33] In all these cases, except *Permian II*, the rate structure also included a moratorium on the filing of rate increases above the established ceilings which expire on January 1, 1976, in the Texas Gulf Coast Area (18 C.F.R. §154.109(a)), July 1, 1976, in the Other Southwest Area (18 C.F.R. §154.109a(a)), and on January 1, 1976, for flowing gas and on January 1, 1977, for new gas in the Southern Louisiana Area (18 C.F.R. §154.105(a)).

[34] Our decision in *Permian II*, 50 F.P.C. 390 (1973), was rendered after this proceeding had been initiated but prior to the time that the rate design set forth in Opinion No. 699 and this opinion was formulated. Since it was desirable to establish rates for the Permian Basin Area rather than defer any action until a decision was finally rendered in this proceeding, that area rate opinion followed our other recent area rate opinions in providing for refund credits and contingent escalations.

adopted the contingent escalations and refund credits as part of a rate structure which included the then prevailing area rates for flowing gas and new gas. See *Mobil Oil Corp.* v. *F.P.C.*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (slip opinion at 11–13 and 34–39).

As we previously noted in this opinion and in Opinion No. 699, the refund credit and contingent escalation provisions of the area rate opinions with the exception of *Permian II* (Opinion No. 662) were coupled with ceiling rates and moratoria on the filing of rate increases above those ceilings. These factors clearly indicate that the refund credits and contingent escalations were intended to be applicable only to those gas supplies that were dedicated to interstate commerce at the ceiling rates prescribed in those opinions. That policy is still valid even though we have established new rates for post-December 31, 1972, dedications of gas to interstate commerce in this proceeding and have pending in Docket No. R–478 a review of the rates for pre-January 1, 1973, dedications.[35] Thus, we conclude that volumes of gas delivered in interstate commerce pursuant to the provisions of section 2.56a shall not also serve to discharge refund obligations or trigger contingent escalations.

The Producers request several clarifications as to the treatment of refund credits and contingent escalations taken prior to the issuance of Opinion No. 699 where the rate is subsequently increased pursuant to that opinion and the effect of filing the waiver after September 21, 1974. The regulations in section 2.56a(j) [formerly §2.56(h)(11)] have been modified to reflect as the effective date of the required waiver the date of filing if the filing is made after September 21, 1974. The other clarification, we think, to be implicit in Opinion No. 699, however, we shall make it explicit. The national rate is obtained by waiving future refund credits and contingent escalations and the waiver required under section 2.56a(i) does not affect refund credits or contingent escalation dedications for volumes of gas delivered prior to the time that a rate increase filing and accompanying waiver under section 2.56a(i) become effective pursuant to section 2.56a(j).

V. Pipeline PGA filings

United Gas Pipe Line Company (United), Panhandle Eastern Pipe Line Company (Panhandle), and Trunkline Gas Company (Trunkline) urge the Commission to allow pipeline companies having purchase gas adjustment (PGA) clauses to make special filings to recover the increased rates provided by Opinion No. 699.[36] We believe that such relief is provided by the statement of policy relating to PGA filings which permits pipelines to recover the increased costs associated with the national rate through the deferred account part of their purchase gas adjustment clauses.[37]

We have determined that jurisdictional pipelines should be permitted to make a one-time special PGA filing to track the rates prescribed in this opinion. Thus, we shall waive the requirements of section 154.38(d)(4)(ii) to permit the filing of this special PGA increase on or before March 3, 1975, to track all increases in purchase gas costs attributable to the national rate which are in effect pursuant to filings made by natural gas producers under section 2.56a(j) on or before January 31, 1975. No other increases in purchase gas cost shall be included in such filing. If a pipeline does not make this special PGA filing on or before March 3, 1975, such pipeline will be permitted to track the rates prescribed in this opinion solely through its regular semiannual PGA filings made after March 3, 1975.

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[35] *Nationwide Rulemaking To Establish Just And Reasonable Rates For Natural Gas Produced From Wells Commenced Before January 1, 1973*, 38 Fed. Reg. 14295 (1973), *see* "Notice Issuing Staff Rate Recommendation And Pre-Scribing Procedures," 39 Fed. Reg. 34304 (September 12, 1974).

[36] *See United Gas Pipe Line Company*, 48 F.P.C. 413, 414 (1972).

[37] F.P.C. (November 1974).

VI. Rates for the Appalachian-Illinois Basin area

Many parties [38] to this proceeding take issue with our application of the national rate to the Appalachian-Illinois Basin Area. In addition to their comments, several of these parties (IOGA, Ohio Oil and Gas Association, and the Columbia companies) submitted studies for the Appalachian area which show that costs are allegedly in the range of 65 to 78 cents per Mcf for that area.

We are not unmindful of the unique nature of the Appalachian area; however, we are of the opinion that a separate rate, whether as a guideline, interim, or permanent rate, for this area should not be promulgated in this proceeding. There is now pending a proceeding upon a petition for special relief from the national rate for producers in the Appalachian area.[39] This proceeding will develop additional information which may be useful in determining whether separate rates should be established for the Appalachian area in the future and the potential level of those separate rates. In order that natural gas producers in this area not be deprived of the flexibility and expeditious nature of the Commission's rulemaking procedures to establish natural gas producer rates, we shall provide that the record in Docket No. RI75–21 will be incorporated into the record of the proceeding in Docket No. RM75–14 which will establish rates for the 1975–76 biennium.[40]

The requests for modification of the national rate regulations promulgated by Opinion No. 699 to establish a separate rate for the Appalachian-Illinois Basin Area are hereby denied.

VII. Rocky Mountain rates and El Paso Natural Gas Company

The Producers allege that we failed to implement our rate orders for the Rocky Mountain Area [41] and that corrective action should be taken by prescribing the rate finally determined in this proceeding as the just and reasonable rate for sales made under Order No. 435. We agree that corrective action should be taken but we do not agree with the extent of the remedy suggested by the Producers and El Paso.

Because Order No. 435 and Opinion No. 658 have resulted in a rather complex rate structure for the Rocky Mountain Area, a brief review of that rate structure is necessary. Order 435 promulgated initial rates at which permanent certificates would be issued without refund obligation for new sales of natural gas made under contracts dated after June 17, 1970.[42] Opinion No. 658 established the just and reasonable rate for sales made under contracts dated prior to October 1, 1968, from wells commenced prior to January 1, 1973. For new sales of natural gas made from wells commenced on or after January 1, 1973, on acreage dedicated under contracts dated prior to October 1, 1968, and for sales made under contracts dated between October 1, 1968, and June 17, 1970, Opinion No. 658 held that the Order 435 rates would apply to such sales until a final order was issued in this proceeding.[43] Thus, if we were to implement the Rocky Mountain orders as suggested by the Producers certain dedications to the interstate market prior to January 1, 1973 would qualify for the rates established in this proceeding while similar sales made in other areas would not qualify for these rates.

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[38] Independent Oil and Gas Association of West Virginia (IOGA), Ohio Oil and Gas Association, Columbia Gas System Companies, Equitable Gas Company, Public Service Commission of the State of New York, Oil and Gas Conservation Commission of the State of West Virginia, Kentucky Oil and Gas Association, and Consolidated Natural Gas Company.

[39] *Independent Oil and Gas Association Of West Virginia*, Docket No. RI75–21.

[40] See 18 C.F.R. §2.56a(m), and n. 99, *supra*.

[41] *Initial Rates For Future Sales Of Natural Gas For All Areas*, Docket Nos. R–389, R–389–A, Order No. 435, 46 F.P.C. 68 (1971), *affirmed sub nom. American Public Gas Association, et al.* v. *FPC*, 498 F.2d (D.C. Cir., May 23, 1974); *Area Rates For The Rocky Mountain Area*, Docket No. R–425, Opinion No. 658, 49 F.P.C. 924 (1973).

[42] Order No. 435, 46 F.P.C. 68, 84, 85 (1971).

[43] 49 F.P.C. 924 at 927.

We find that rates for the Rocky Mountain Area for contracts dated on or after October 1, 1968, where the sales do not qualify for the national rate pursuant to section 2.56a(a)(2) [18 C.F.R. §2.56a(a)(2)], shall be 35 cents per Mcf.[44] This rate is based upon our analysis of the cost studies incorporated in Order No. 435[45] and the rates, based upon national data, established in *Permian II.*[46] This rate is exclusive of all production, severance, or similar taxes, State or Federal, and subject to quality adjustments and gathering. All amounts collected in excess of these rates subject to refund shall be refunded to the purchaser for flow through to the ultimate parties who paid excessive rates for such gas.[47]

Table III indicates that the amount of refunds required by the promulgation of a 35 cents per Mcf rate is not significant. There is, of course, a pressing need for additional capital to finance exploration and development activities, but we believe that the public interest requires that just and reasonable rates for past periods be finally rendered for sales made in the Rocky Mountain Area. The rates for future periods for sales made in all areas will be determined in this proceeding, Docket No. R-478, and Docket No. RM75——.

VIII. Small producers

Several questions regarding the interrelationship of the national rate and just and reasonable rates for small producers including the effective date of the rates promulgated in Opinion No. 699 were raised.

The effective date of the rates promulgated by Opinion No. 699 is June 21, 1974.[48]

Pending the resolution of the applicable standards upon which the justness and reasonableness of small producer rates will be determined,[49] small producers are entitled to collect the national rate for qualifying sales on and after June 21, 1974, without a refund obligation.

There may be some confusion with respect to the language pertaining to expiring contracts at page 108 of Opinion No. 699. As with expiring contracts entered into by large producers, small producers must execute a renewal contract which qualifies pursuant to section 2.56(a)(2)(iii) before they are eligible to collect the rate prescribed in section 2.56a(a)(1) for such continued sales.

IX. Clarifications and modifications

There are also a number of other matters which should be mentioned. These matters relate to certain technical modifications and amendments to the national rate regulations.

A. CODIFICATION OF NATIONAL RATE REGULATIONS

Opinion No. 699 provided that the national rate regulations would be codified as subsection (h) of section 2.56 of the Commission's Statements of General Policy And Interpretations (18 C.F.R. §2.56) entitled "Area Price Levels for Natural Gas Sales by Independent Producers." Upon further consideration of this codification, we believe that the national rate regulations should be codified as a separate section of the Statements of General Policy And Interpretations to avoid confusion with the guideline and initial rate provisions of section 2.56.

Thus, we have deleted section 2.56(h) and codified the amended national rate regulations as section 2.56a. Section 2.56a(o) provides for amendment of all certificates which have been issued pursuant to section 2.56(h) to reflect the change in codification.

B. APPENDIX D

The Producers request that footnote 4 to Appendix D be altered to reflect the language of section 2.56(h)(7) [now section 2.56a(e)]. The second sentence of

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[44] This rate shall also apply to qualifying sales prior to June 21, 1974.

[45] 46 F.P.C. 63 at 84.

[46] 50 F.P.C. 390 (1973).

[47] Because of our treatment of refund credit and contingent escalation provisions, *supra* at 60–63 we find that such provisions should not be included in the rate structure for the Rocky Mountain Area.

[48] *Infra* at 71.

[49] *Small Producer Regulation*, Docket No. R-393, "Notice of Proposed Rulemaking," 39 Fed. Reg. 33241 (September 1974).

that footnote reads: "Note that only natural gas produced in offshore areas actually delivered onshore by producer's facilities qualifies for this adjustment." The sentence should read: "Note that only natural gas produced in offshore areas which is actually delivered onshore at the sole cost of the producer qualifies for this adjustment."

C. EFFECTIVE DATE OF OPINION NO. 699

Several parties have requested clarification as to the effective date of the rates prescribed in Opinion No. 699. The effective date of the national rate prescribed in section 2.56a (formerly section 2.56h)) is June 21, 1974.

The rate which is prescribed by this opinion is being made effective June 21, 1974, to assure that the national rate will provide the rate of return determined to be just and reasonable in Opinion No. 699 and this opinion, pursuant to the Commission's authority upon rehearing "to abrogate or modify its order without further hearing." [50] Such an effective date is necessary to assure that those persons selling natural gas in interstate commerce will receive the rates which this Commission has ultimately found to be just and reasonable.

D. MISCELLANEOUS AMENDMENTS

A number of parties presented to the Commission on rehearing requests for clarifications of the promulgated national rate regulations. In many cases these clarifications have been incorporated in the amended national rate regulations without explicit discussion in this opinion. To the extent that the proposed clarifications are reflected in the amended regulations, these requests for modification of Opinion No. 699 and the regulations promulgated thereunder are granted. Those requests which are not reflected in the amended regulations promulgated by this opinion are hereby denied.

X. *Conclusion*

By Opinion No. 699 and this opinion, we establish a rate design for new gas [51] sold in interstate commerce. Each of the elements of the rate structure is interdependent upon all of the other elements and stands not by itself but as part of the whole. In summary, the total rate design herein found to be just and reasonable consists of the following integral elements:

1. A base rate of 50.0 cents per Mcf (with annual escalations of 1.0 cents per Mcf) subject to Btu adjustment plus reimbursement for production, severance, or similar taxes, and gathering allowances (including the onshore delivery of offshore gas at the cost of the producer) for qualifying sales;
2. Allowance of the national rate for sales formerly made pursuant to contracts which have expired by their own terms where a qualifying renewal contract is submitted to the Commission for certification;
3. A biennial review to prescribe prospective just and reasonable rates for those sales which qualify for the national rate; and
4. Provisions for special relief from the national rate.

We have "adopted a total rate structure to motivate private producers to fully develop [the nation's natural gas] resources" [52] while assuring the consumer an adequate supply of gas at a reasonable rate. This "total rate structure" as promulgated in Opinion No. 699 and supplemented and modified by this opinion represents a solution "capable of equitably reconciling the diverse and conflicting interests" [53] which are presented on the record of this proceeding. It

[50] 52 Stat. 831 (1938), 15 U.S.C. §717r (1970); *see also* 52 Stat. 830 (1938), 15 U.S.C. §717o (1970); *cf. Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (slip opinion at 23–25); *Austral Oil Co.* v. *FPC*. 428 F.2d 407, 444–445, *on rehearing*, 444 F.2d 125, 126–127 (5th Cir.), *cert. denied sub nom. Municipal Distributors Group* v. *FPC*, 400 U.S. 950 (1970).

[51] New gas is that gas which qualifies under one or more of the provisions of section 2.56a(a)(2).

[52] *Placid Oil Co.* v. *FPC*, 483 F.2d 880, 891 (1973), *affirmed sub nom. Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (see slip opinion at 43).

[53] *Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (slip opinion at 43) *citing Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968).

is true that certain portions of this rate structure favors some producers or some consumers more than other members of those classes of persons. There is always "some discrimination aris[ing] from the mere fact of [national], rather than individual producer, regulation,"[54] but such discrimination is permissible if the overall balance of the order is not unjust and unreasonable. We are of the opinion that the "overall balance" of the rate structure established herein is just and reasonable.

The Commission, acting pursuant to the provisions of the Natural Gas Act, as amended, particularly Sections 4, 5, 7, 8, 14, 15, and 16 thereof (52 Stat. 822, 823, 824, 825, 828, 829, 830 (1938); 56 Stat. 83, 84 (1942); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. §§717c, 717d, 717f, 717g, 717m, 717n, 717o (1970)0, *orders:*

(A) The Statements of General Policy and Interpretations of The Commission, Part 2 of Subchapter A of Chapter I of Title 18 of the Code of Federal Regulations, are hereby amended by deleting Section 2.56(h) adding a new Section 2.56a as follows:

2.56a National Rate For Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973.

(*a*) *Base National Rate*

(1) Notwithstanding any other provisions of the General Rules of the Federal Power Commission, or the Regulations Under the Natural Gas Act, sales of natural gas which qualify under the provisions of one or more of the classifications set forth in paragraph (2) may be made in interstate commerce at a rate not to exceed 50.0 cents per Mcf (at 14.73 psia), exclusive of all State or Federal production, severance or similar taxes, and subject to the adjustments provided in this Section 2.56a.

(2) Sales of natural gas in interstate commerce for resale may be made at the rate prescribed in paragraph (1) of this subsection provided the provisions of one or more of the following classifications apply to such sales:

(i) The sale is made from a well or wells commenced on or after January 1, 1973;

(ii) Sales made pursuant to contracts for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1973, except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, *et al.*), or 18 C.F.R. § 2.75(n), where such sales are initiated on or after January 1, 1973, provided that no certificate for the subject sale has been issued under the optional procedure (18 C.F.R. § 2.75);

(iii) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

(3) The price prescribed by this Subsection (a) may be increased by an amount not to exceed 1.0 cents per Mcf per annum commencing on January 1, 1975, and the first day of every year thereafter for the term of the contract dedicating the subject gas for sale in interstate commerce pursuant to the terms of the sales contract until such time as the price prescribed in paragraph (1) of this subsection (a) shall be redetermined according to the provisions of Subsection (n) of this section 2.56a.

(*b*) *Tax adjustments*

The applicable rate prescribed in subsection (a) shall be adjusted upward for all State or Federal production, severance, or similar taxes, effective the date deliveries are commenced, and shall be adjusted upward by 100 percent of any

[54] *Mobil Oil Corp.* v. *FPC*, slip opinion at 37.

increase in such taxes subsequent to the date deliveries were commenced, and shall be adjusted downward by 100 percent of any decrease in such taxes subsequent to the date deliveries were commenced.

(c) *Qualify adjustments*

For natural gas sold in interstate commerce for resale subject to the rate prescribed in subsection (a) of this section, quality standards and the resulting adjustments to the base national rate shall be made as follows:

(*1*) *Btu adjustment*

For natural gas containing more than 1,000 Btu's per cubic foot, at 60°F. and 14.73 psia, upward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot; and for natural gas containing less than 1,000 Btu's per cubic foot, at 60°F. and 14.73 psia, downward adjustments shall be made on a proportional basis from a least of 1,000 Btu's per cubic foot.

This adjustment shall be made after the rate prescribed in subsection (a)(1) is adjusted for taxes pursuant to subsection (b).

The Btu content of the natural gas used in computing this rate adjustment shall be the number of British thermal units (Btu) produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1.0 cubic feet at a temperature of 60°F. saturated with water vapor and under a pressure equivalent to that of 30.00 inches of mercury at 32°F. and under standard gravitational force (980.665 centimeters per second squared) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air and when the water formed by combustion is condensed to the liquid state.

(*2*) *Other quality adjustments*

All quality standards and the resulting adjustments to the rate prescribed in subsection (a)(1) shall be made in accordance with the provisions of the particular gas sales contract except that all Btu adjustments shall be governed by paragraph (1) of this subsection.

(*d*) *Gathering allowances*

The base national rate prescribed in subsection (a) of this section, as adjusted for Btu content and applicable taxes, shall be adjusted for gathering activities as follows:

(*1*) *Appalachian-Illinois Basin Areas.*—The gathering allowance shall be 1.0 cents per Mcf for all sales of natural gas made from wells located in the Appalachian-Illinois Basin Areas.

(*2*) *Hugoton-Anadarko Area.*—The gathering allowance shall be the amounts prescribed below where delivery of the gas is made after substantial off-lease gathering by the producer, whether at a plant tailgate or at a central point in the field.

(A) For gas produced in the Panhandle and Hugoton Fields, the allowance shall be 2.5 cents per Mcf.

(B) For gas produced from fields or reservoirs other than the Panhandle or Hugoton Fields (the "Other Fields"), the allowance shall be 1.0 cents per Mcf.

(*3*) *Other Southwest Area.*—The gathering allowance shall be the amounts prescribed below where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(A) For gas produced in the Other Oklahoma Area, Texas Railroad District No. 9, and Northern Arkansas, the allowance shall be 1.5 cents per Mcf.

(B) For gas produced in Texas Railroad District Nos. 5 and 6, Northern Louisiana, and Southern Arkansas, the allowance shall be 1.0 cents per Mcf.

(C) For gas produced in Mississippi and Alabama, the allowance shall be 1.25 cents per Mcf.

(*4*) *Permian Basin Area.*—For gas produced in the Permian Basin Area, the applicable gathering allowance shall be 1.5 cents per Mcf where delivery is made after substantial off-lease gathering by the producer, whether at a plant tailgate or a central point in the field.

(5) *Rocky Mountain Area.*—For gas produced in the Rocky Mountain Area, the applicable gathering allowance shall be 1.0 cents per Mcf where delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

(6) *Southern Louisiana Area.*—For gas produced in the Southern Louisiana Area, the applicable gathering allowance shall be 0.5 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(7) *Texas Gulf Coast Area.*—For gas produced in the Texas Gulf Coast Area, the applicable gathering allowance shall be 0.4 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(*e*) *Delivery of offshore gas by the producer to an onshore area*

If natural gas produced offshore is delivered onshore, at the sole cost of producer, the uniform national rate shall be adjusted upward 1.0 cent per Mcf for such offshore gas.

(*f*) *Adjusted national rate*

The uniform national rate prescribed in subsection (a), as adjusted pursuant to subsections (b), (c), (d), and (e), is the adjusted national rate, and such rate is applicable only to those jurisdictional sales described in subsection (a)(2) made within the United States including the adjacent offshore Federal domain but excluding Alaska and Hawaii. No seller may demand or receive any rate or charge in excess of the rate prescribed by subsection (a), except for such adjustments described in subsections (b), (c), (d), and (e) of this section as may be applicable to the particular sale, unless the Commission after giving proper notice and providing an opportunity for the submission of comments shall modify the rate set forth in subsection (a) or grant a petition for special relief pursuant to subsection (g) of this section.

(*g*) *Special relief*

Prior to the establishment of rates for the 1975–76 biennium pursuant to subsection (n), any seller seeking to charge a rate in excess of the adjusted national rate described in subsection (f) of this section or requesting a change in either the base national rate prescribed in subsection (a)(1) or the adjusted national rate described in subsection (f) must file a petition seeking special relief for waiver or amendment of said subsections pursuant to Section 1.7(b) of the Commission's Rules of Practice and Procedure (18 C.F.R. §1.7(b) fully justifying the relief sought in light of this order. Such seller may not file for any rate increase which results in a rate in excess of the adjusted national rate described in subsection (f) unless and until the Commission grants such petition for special relief.

(*1*) *Federal Income Taxes.*—For those cases where a producer seeks special relief on the grounds that a Federal income tax liability has been incurred with respect to the producer's total jurisdictional natural gas operations, the producer shall submit certified copies of the appropriate Federal income tax returns and supporting schedules required by Treas. Regs. §§1.611-2(g), 1.613-6 (26 C.F.R. §§1.611-2(g), 1.613-6) as part of the petition for special relief.

(2) *Drilling Depths Greater Than 15,000 Feet and Water Depths Greater Than 250 Feet.*—For sales of natural gas made from wells with a total depth greater than 15,000 feet (8,000 feet in the Appalachian and Illinois Basin Areas) and/or located in water depths greater than 250 feet, the seller may petition the Commission for relief from the rate established in subsection (a)(1) and such relief may be granted by the Commission upon a showing that total cost of producing such gas is in excess of the rate established in this decision.

(*h*) *Modification of Area Rate Regulations*

To the extent that the Commission's Regulations Under the Natural Gas Act establishing area rates and conditions for sale of natural gas from the Southern Louisiana Area (18 C.F.R. §154.105), Hugoton-Anadarko Area (18 C.F.R. §154.106), Appalachian Basin Area (18 C.F.R. §154.107), Illinois Basin Area

(18 C.F.R. §154.109), Other Southwest Area (18 C.F.R. §154.109a), or Rocky Mountain Area (18 C.F.R. §§2.56(a), 154.109(b)), and the Permian Basin Area are inconsistent with the provisions set forth above the same are hereby modified to reflect the provisions set forth above. The provisions of the rate structures for these are modified only with respect to those sales which are certificated pursuant to the provisions of this section and in all other respects remain in full force and effect. Provisions pertaining to refund credits and contingent escalations are contained in subsection (i).

(*i*) *Waiver of refund credits and contingent escalations*

Any natural gas certificated under the provisions of this section which a natural gas producer elects to have credited against his existing refund obligations in the Southern Louisiana, Texas Gulf Coast, Other Southwest Area, or the Permian Basin, or applied to the triggering volumes for the contingent escalations for those areas shall be priced at the rate prescribed in the applicable area rate opinion and not at the uniform national rate prescribed in this opinion. For purposes of this section, the applicable area rate opinions and Commission regulations are:

(a) *Area Rate Proceeding* (*Texas Gulf Coast Area*), *et al.*, Opinion No. 595, 45 F.P.C. 675 (1971); 18 C.F.R. §154.109.

(b) *Area Rate Proceeding* (*Southern Louisiana Area*), *et al.*, Opinion No. 598, 46 F.P.C. 86 (1971); 18 C.F.R. §154.195.

(c) *Area Rate Proceeding* (*Other Southwest Area*), *et al.*, Opinion No. 607–A, 47 F.P.C. 99 (1972); 18 C.F.R. §154.109a.

(d) *Area Rate Proceeding* (*Permian Basin Area II*), Docket No. AR70–1 (Phase I), Opinion No. 662, 50 F.P.C. 390 (1973).

With respect to gas of a class described in subsection (a)(2) which is currently being sold in interstate commerce in discharge of a refund obligation or was dedicated to interstate commerce in partial satisfaction of the triggering volumes for the contingent escalations in the described areas, such gas may be sold at the rate prescribed in subsection (a) only if the seller files a written waiver of the right with respect to such gas to discharge such refund obligations or to trigger the contingent escalations concurrently with the contractually authorized rate increase filing. The seller shall further state the date on which the subject wells were commenced, the present provisions under which the gas is being sold in interstate commerce, the dollar amount of existing refund obligations previously discharged by the sale of such gas, and the volumes (at 14.73 psia) applied to trigger the contingent escalations.

(*j*) *Effective date of rate filings and waivers of refund credits or contingent escalations*

Any contractually authorized increase rate filing and/or written waiver of refund credits or contingent escalations made pursuant to the provisions of this order shall be effective as of June 21, 1974, if the filing is made on or before January 31, 1975, and as of the date of filing if the filing is made subsequent thereto. Such filings may include the 1.0 cents per Mcf annual escalation to be effective January 1, 1975.

(*k*) *Newly discovered reservoirs on previously committed acreage*

(1) In all areas, the rate for natural gas produced from a reservoir discovered on or after January 1, 1973, which is located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall be determined by the date of discovery of such reservoir, in lieu of the contract date.

(2) Where a producer is entitled to an increase in the price of its gas based on the date of discovery of the reservoir from which gas-well gas sales (or residue gas derived therefrom) are being made, it may file a proposed price increase pursuant to section 4 of the Natural Gas Act, indicating to what gas the higher price will be applicable. With each filing the producer will include (i) copies of all documents filed with or issued by local or State regulatory agencies relating to the discovery of the reservoir from which the gas is produced, and (ii) a statement by the buyer of the gas that the gas qualifies for the price sought, or why the buyer believes it does not. The producer shall also furnish any additional material in its possession or available to it which the

Commission may request in writing. Documents or other data previously filed with this Commission, whether by the producer or another, may be incorporated by reference in any filing hereunder. Similar information shall be filed in any pending section 4 proceeding to which it is relevant. The Commission will follow the determination made by the appropriate State agency in determining the date of discovery of a reservoir. In the event the State agency changes its classification of a reservoir, the Commission shall follow such change as of the date of the new classification. Whenever the reclassification of a reservoir effects the applicable ceiling rate the producer and the buyer shall notify the Commission.

(*l*) *Pipeline Production.*—Natural gas production from leases owned by a pipeline or a pipeline affiliate may be priced at the rate prescribed in subsection (a) pursuant to the provisions of Section 2.66(c) of this part (18 C.F.R. §2.66(c)).

(*m*) *Termination of rate ceiling*

The rate prescribed in subsection (a)(1) shall remain in effect until such time as rates are established pursuant to subsection (n).

(*n*) *Review of national rate ceiling*

Prior to January 1, 1975, the Commission shall initiate such proceedings as shall be necessary to establish a just and reasonable rate to be effective from the date of establishment of rates by order of the Commission through December 31, 1976, for the sales described in subsection (a)(2) and for all wells commenced on or after January 1, 1975, and prior to January 1, 1977, all new dedications of natural gas to interstate commerce for the period January 1, 1975, through December 31, 1976, and all renewal contracts taking effect for the period January 1, 1975, through December 31, 1976.

(*o*) *Revision of section 2.56(h) (18) C.F.R. §2.56(h)*

By Opinion No. 699, the Commission promulgated a national rate structure as subsection (h) of Section 2.56 of its General Policy Statements and Interpretations (18 C.F.R. §2.56(h)). By this Opinion No. 699-E, said section 2.56(h) is revised and designated as Section 2.56a (18 C.F.R. §2.56a). All certificates which may have been issued prior to this date pursuant to Section 2.56(h) are hereby amended to reflect the change in codification of the national rate structure.

(*p*) *Effective date*

The effective date of this section 2.56a is June 21, 1974.

(B) Section 2.56(f) of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, is amended by adding a new paragraph (3):

(*3*) *Reservoirs Discovered or Dedicated to Interstate Commerce On or After January 1, 1973.*—The rate for new reservoirs discovered or dedicated to interstate commerce on or after January 1, 1973, shall be determined by Section 2.56a(a) if the proposed sale comes within one of the classes enumerated in Section 2.56a(a)(1)

(C) Section 2.66 of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18 of the Code of Federal Regulations, is amended by adding a new subsection (c) as follows:

(*c*) *National rate for pipeline or pipeline affiliate production*

Notwithstanding any other provision of this section 2.66, natural gas production from any lease owned by a pipeline company or a pipeline affiliate, regardless of the date of acquisition of the lease, shall be priced for ratemaking purposes at the rate prescribed in section 2.56a(a)(1) of this part if such production qualifies under the provisions of one or more of the enumerated classes of sales set forth in section 2.56a(a)(2) of this part. The provisions of Section 2.56(f) (18 C.F.R. §2.56(f)) shall apply to natural gas production which qualifies for the national rate treatment pursuant to this subsection (c).

(D) Notwithstanding the provisions of section 154.38(d)(4)(iv) of the Regulations Under the Natural Gas Act (18 C.F.R. §154.38(d)(4)iv)), any jurisdictional pipeline company having a purchase gas adjustment clause in effect on June 21, 1974, and thereafter, pursuant to section 154.38(d)(4), may file on or before March 3, 1975, a special rate increase to track the rates prescribed in section 2.56a (18 C.F.R. §2.56(a)) effective as of the date of the filing, provided such rates are in effect pursuant to filings made by natural gas producers pursuant to section 2.56a(j) on or before January 31, 1975.

(E) Section 154.109b of the Commission's Regulations Under the Natural Gas Act, Part 154 of Subchapter E of Chapter I, Title 18, Code of Federal Regulations, is hereby amended by adding a new subsection (d):

(d) No rate or charge, made, demanded, or received under a rate schedule filed pursuant to this part for gas produced in the Rocky Mountain Area shall exceed 35.0 cents per Mcf measured at 14.73 psia and 60°F, subject to adjustment upward and downward Btu adjustment on a proportional basis from a base Btu content of 1,000 Btu's per cubic foot measured on a saturated basis, and exclusive of all State or Federal production, severance, or similar taxes, and sold under contracts dated on or after October 1, 1968, for wells commenced prior to January 1, 1973. This rate shall also be subject to a gathering allowance not to exceed 1.0 cents per Mcf where delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

By the Commission. Commissioner Brooke, concurring, filed a separate statement appended hereto. Commissioner Springer, concurring in part and dissenting in part, filed a separate statement appended hereto. Commissioner Smith, concurring in part and dissenting in part, filed a separate statement appended hereto. Commissioner Moody, dissenting, filed a separate statement appended hereto.

MARY B. KIDD, *Acting Secretary.*

TABLE I.—NONASSOCIATED GAS RESERVE ADDITIONS FOR THE UNITED STATES[1] (EXCLUDES ALASKAN DATA)

[Million cubic feet at 14.73 ps/in²a]

Year	Revisions (a)	Extensions (b)	New field (c)	New reservoir (d)	Total[2] (e)	Total excluding revisions (f)
1966	3,056,812	7,490,746	2,813,222	2,775,360	16,136,140	13,079,328
1967	3,712,892	8,625,273	2,819,635	2,126,298	17,284,098	13,571,206
1968	4,036,210	5,864,521	1,206,628	1,227,600	12,334,959	8,298,749
1969	(1,440,196)	4,788,627	1,663,266	1,863,021	6,874,718	8,314,914
1970	(290,034)	4,886,132	1,556,494	3,198,724	9,351,316	9,641,350
1971	(1,471,410)	5,625,841	1,176,939	3,234,033	8,565,403	10,036,813
1972	(1,911,097)	5,449,052	1,264,756	2,794,559	7,597,270	9,508,367
1973	(5,347,021)	5,305,857	1,968,520	1,789,574	3,734,930	9,063,951

[1] "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of Dec. 31, 1973," vol. 28, published jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (June 1974).

[2] These totals equal the summation of cols. (a) through (d). The parentheses ( ) in col. (a) denote negative amounts.

TABLE II.—REVISIONS TO NONASSOCIATED NATURAL GAS RESERVES (TOTAL UNITED STATES, EXCLUDING ALASKA)

[Billions of cubic feet (Bcf) at 14.73 lb/in²a, 60° F.]

	1966	1967	1968	1969	1970	1971	1972	1973
Positive revisions	4,323	5,713	6,234	1,368	2,208	2,000	1,426	1,422
Negative revisions	(1,276)	(2,001)	(2,200)	(2,812)	(2,500)	(3,471)	(3,337)	(6,763)
Net	3,056	3,712	4,034	1,444	(292)	(1,471)	(1,911)	(5,341)

Figs. in parentheses indicate negative volumes.

Source: Comments of united distribution companies in response to notice issued Mar. 21, 1974, separate appendix prepared by William J. Ogden, table 6 (May 7, 1974).

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TABLE III.—ROCKY MOUNTAIN AREA, RATES SUBJECT TO REFUND WHERE BASE RATE IS IN EXCESS OF 30 CENTS PER THOUSAND CUBIC FEET

Producer—P/L	Docket No.	Base rate (cents)	R/S No.	Supp. No.	Estimated annual amount suspended	Estimated annual volume (a)	Date rate, ESR	Portion of rate in excess of 30 cents (b)	Portion of rate in excess of 35 cents (c)	Portion of rate in excess of 42 cents (d)	Monthly revenue from portion of rate in excess of 30 cents (e)	Monthly revenue from portion of rate in excess of 35 cents (f)	Monthly revenue from portion of rate in excess of 42 cents (g)
Montana-Wyoming:													
High Crest Northern	RI74-79	40.0	1	4	$1,879,819	9,125,000	May 9, 1974	10.0	5.0		$76,042	$38,021	
Do	RI74-174	40.0	2	4	208,310	1,080,000	Aug. 22, 1974	10.0	5.0		9,000	4,500	
Amoco Col. Interstate	RI74-66	41.02	582	3	12,748	700,000	Apr. 23, 1974	11.02	6.02	1.02	6,428	3,512	$595
Champlin Mountain Fuel.	RI74-233	40.0	125	2	112,380	600,000	Oct. 19, 1974	10.0	5.0				
Belco Mountain Fuel	RI73-196	32.0	7	12	320	100,000	Apr. 23, 1974	2.0			167		
Do	RI74-190	33.0	7	11	8,112	600,000	Aug. 31, 1974	3.0			1,500		
San Juan:													
Aztec, El Paso	RI74-144	52.16	35	11	41,371	120,791	July 2, 1974	22.16	17.16	10.16	2,231	1,727	1,023
Do	RI74-144	52.16	29	10	52,943	158,095	do	22.16	17.16	10.16	2,920	2,261	1,339
Do	RI74-144	52.16	28	8	16,502	48,182	do	22.16	17.16	10.16	890	689	408
Do	RI74-144	52.16	12	13	707	2,065	do	22.16	17.16	10.16	38	30	18
Do	RI74-144	52.16	5	8	15,225	44,450	do	22.16	17.16	10.16	821	636	376
Do	RI74-144	52.16	4	39	158,485	462,733	do	22.16	17.16	10.16	8,545	6,617	3,918
Do	RI74-144	52.16	3	31	547,271	1,597,870	do	22.16	17.16	10.16	29,507	22,850	13,529
Amerada Hess, El Paso.	RI75-31	52.16	25	8	415,097	1,248,788	Feb. 12, 1975	22.16	17.16	10.16			
Do	RI75-31	52.16	49	13	392,321	1,390,717	do	22.16	17.16	10.16			
Do	RI75-31	52.16	50	18	55,001	169,027	do	22.16	17.16	10.16			
Total											138,089	80,843	21,206

OPINION No. 699-H

JUST AND REASONABLE NATURAL RATES FOR SALES OF NATURAL GAS FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1. 1973—DOCKET NO. R-389-B

(December 4, 1974)

BROOKE, Commissioner, *concurring:*

I concur in the instant order on rehearing of Opinion No. 699, not that I am convinced of its adequacy to maximize the search for new interstate gas supplies but because it does represent a departure from the hitherto sancrosanct Permian costing methodology and movement toward a more realistic economic method for determining the most effective level of producer rates.

Commissioner Moody's dissent details and develops at some length many of the inadequacies and infirmities of the modified national rate order herein adopted, and I am in strong agreement with his analysis and conclusions. However, I am compelled to concur in the order, despite these serious misgivings, because the public interest demands its issuance without further delay, for two major reasons: (1) the producing and pipeline industries and the ultimate consumers are entitled to this early answer to the rate and other important issues, and (2) it is urgent to clear Opinion No. 699-H so we may proceed immediately with the 1975-76 biennium rate review.

Although substantial legal precedents permit considerable latitude in prescribing a just and reasonable national rate, the Commission has chosen to nibble at, rather than take the big bite of the apple that I feel could be legally justified and sustainable on the present record.

Adjusting the Permian model by utilizing discounted cash flow (DCF) to assure a constant 15 percent return on all invested funds over the life of the investment and trending successful and dry hole costs is a substantial improvement in rate-making methodology. While completely agreeing with this modification, it can only be viewed as a beginning step toward more responsive and viable procedures attuned to the desperate need to expand the nation's supplies of *new* natural gas reserves.

The total modified rate for 1973-4 prescribed herein—a base rate of 50 cents plus adjustments—is a much improved incentive, but I regard it as woefully inadequate to enable the interstate pipelines to compete with any degree of effectiveness for new on-shore supplies. Again, the modified 50-cent base rate is entirely cost-based and omits inclusion or consideration of reasonable non-cost add-ons the courts later held to be lawfully permissible where justified. More weight should have been attached to these non-cost factors.

If E&D were directed solely to develop new supplies for the interstate market, the national rate derived herein undoubtedly would be most attractive to potential investors. The precise relationship of price and supply is impossible to define, but it is noteworthy that higher rates, both intrastate and interstate, have been accompanied by a significant increase in drilling activity the past two years, most of it on-shore. This points up the simple economic fact that high intrastate prices are an effective damper on producer enthusiasm to develop on-shore reserves for the interstate market. I am confident nevertheless that the improved incentives will yield some benefits to the interstate consumer; that rate incentives plus improved cash flow on contract renewals will tend to accelerate off-shore federal domain, and that new entrants may now find gas E&D worth the gamble.

The ultimate effectiveness of the new rate can only be demonstrated through time and experience. It undoubtedly will be more helpful than old rate levels, but it falls short of providing the incentive required to maximize development of the nation's natural gas resource base at this critical juncture of our American livelihood. Curtailments of pipeline supplies are deepening. The producibility from old established reservoirs is dwindling, and living from these inventories will be more difficult and more costly each year. Experts may disagree on the extent of the nation's natural gas potential, but there is universal agreement that the vast bulk of future supplies is in deep on-shore and off-shore horizons below 15,000 feet, in deep water offshore, in deep tight-bearing formations, in marginal areas previously unattractive economically, and in Alaska—all representing the probability of substantial investment.

Converting the natural gas potential from these sources into deliverable supplies will require an enormous investment of capital, which will not be committed in the absence of incentives which render the expectation of adequate return with greater certainty than the anticipation of loss. Unless a sharp reversal of domestic natural gas supply trends occurs within the next couple of years, the national goal of self-sufficiency will be delayed; curtailments and allocations will impose severe hardships on industry, and, probably, on human needs customers; dependency on foreign suppliers will mount, and prices will increase. The ultimate loser, or course, will be the consumer—the person whom the Natural Gas Act was devised to protect.

ALBERT B. BROOKE, JR., *Commissioner.*

OPINION NO. 699–H

JUST AND REASONABLE NATIONAL RATES FOR SALES OF NATURAL GAS FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973—DOCKET NO. R–389–B

(December 4, 1974)

SPRINGER, Commissioner, *Concurring in Part and Dissenting in Part:*

A HISTORY OF AREA AND NATIONAL RATES 1968–JUNE 1974

In determining the legality of the rule establishing a national rate perhaps a short history is in order.

In 1960, the Federal Power Commission decided to establish area rates rather than regulating on an individual company basis.

The first area rate decision was issued in 1965 and was affirmed in 1968 by the U.S. Supreme Court in the Permian Basin area rate case (390 U.S. 747). In that decision the Commission determined the rates for regulated companies on the basis of the recovery of all of their reasonable expenses, including a fair return on their investment in used and useful properties. In all succeeding area rate cases this method was used in determining the rates including a fair return.

In reaching our decision on June 21, 1974, in Opinion 699 as to a national rate, we followed this method which has been approved by the Courts innumerable times. We computed our nationwide rates on the basis that a fair return on the investment producers had made for the benefit of consumers was 15%.

It cannot be emphasized too strongly that since this Commission first initiated under R–389–B a proposed rulemaking to determine rates on a nationwide basis, it has consistently applied the methodology approved in its previous area rate cases in reaching a nationwide rate.

On June 21 in this proceeding the Commission issued Opinion 699 wherein we determined that a nationwide price of 42¢ plus one cent annual escalation was the proper price for all gas sold on or after January 1, 1973, from wells or contracts after that date. In determining that 42¢ was the proper rate, we were presented with cost evidence by our staff and others indicating that the range of cost using our approved methodology was between 38 and 42 cents and thus we granted a rate at the high end of that range. We adopted the high range in order to assure the producers that they would have every incentive to find and sell additional gas in the interstate market.

The methodology used in the overall determination of a nationwide rate in 699 on June 21, 1974, is a method which has been specifically approved by the courts in the Permian Basin case (supra) and the South Louisiana case (Placid Oil Co. v. FPC, 483 F.2d 880, 5 Cir. 1973).

THE NEW METHODOLOGY

As modified by this proposed opinion, we are increasing that rate which was already at the high end of the range by nearly 20%; from 42¢ to 50¢. This is being accomplished in two ways: First, the majority has decided that a completely new method for determining the proper rate of return to be applied, and secondly, they have added to this a form of trending based on speculation as to the future.

Opinion 699, issued on June 21, was adopted after the Commission had received comments from all interested parties as to the proposed rates and given them full and careful consideration. Numerous applications for rehearing for further consideration and on August 22 and 23, 1974, we heard oral arguments from all of the parties requesting rehearing.

After receiving court approval in those cases of the methodology for calculating producer rate, and after working long and hard to apply this methodology to determining a nationwide rate, we suddenly see in the last few weeks a change by the majority to a new methodology.

THE NEW METHODOLOGY AND THE PRODUCER REQUESTS

What is the effect of the new methodology? Perhaps a little history of producer requests are in order.

In South Louisiana settlement approved by the Commission on July 16, 1971, the producers assured us that a 26¢ rate would bring forth all the gas needed in the years to come. That was barely 39 months ago. Now the majority is ready to find that either the producers didn't know what they were talking about, or the Commission should never have listened to them. By the proposed opinion, the majority is increasing the rate by almost 100% from 26¢ to 51¢ Mcf, as of this date.

RATE OF RETURN

I have no objection to examining new methods of regulation when the time is ripe, but to do so at the end of an already decided case strikes me as unusual. More importantly to strike out on a new method of determining rates with as little consideration as seems to be given in this case is something unacceptable to me. The majority starts off with the assumption that their 15% return on investment is a fixed number which cannot be changed when you switch your methodology. They take the 15% allowed on the total rate base and translate it into a discounted cash flow on all producer cost without examining the effect on the traditional methodology of doing this. Let us understand this in the most simple terms. Computed roughly, by switching the methodology, the majority is now saying that producers are entitled to a 23% return on their productive investment.

The majority does not discuss why they needed 23%. Neither do they discuss how this compares with the return received by other industries on productive investment, and basically do nothing but grant the substantial increase without an analytical examination of its need or effect.

I cannot but presume that all companies regulated by this Commission-producer, pipeline, and power-will now be entitled to argue that the latest return the majority determined to be reasonable should be translated by the DCF method to a return, in effect, several percentage points higher, since no adjustment is made to the basic starting point for the use of the DCF method.

Under the DCF approach, the rate of return is the discount rate which equates a projected future flow of income to the present market price of equity. I am not prepared to make a sophisticated analysis of this concept for the gas producer industry, but neither am I ready to adopt the numbers used by the majority without more analysis than they have given them. What they have done is take the figures from Opinion 699, adopted June 21, 1974, and translate them into a DCF method with little or no analysis at all.

ATTRACTING GAS TO THE INTERSTATE MARKET

Without commenting on the use of questionable trending in addition to the DCF method as a means of raising nationwide points should be noted. First, a use of annual escalations in these rates means that even when we issue Opinion 699, we were talking about 43 cents, and by January 1, 1975, will be talking about 44 cents.

The majority seems to feel that this is a price which will not elicit a supply of gas. However, I noted that in the last month at least 16 producers who had contracts at rates well in excess of 43¢ set by Opinion 699, have agreed to accept certificates at that rate. I cannot believe that they would accept this rate if they felt they were not going to earn a fair return at that figure.

Secondly, as noted above, it was only three years ago that producers told us 26¢ would elicit the supply of gas we needed. While I realize costs have increased, it must be remembered that costs of domestic production have only increased so much and it is only this additional cost we should be trying to allow. I cannot believe that in three years inflation has raised costs 100 percent, nor that in agreeing to a 26¢ price, the producers were not aware at that time that some inflation was bound to occur.

LIMITED TERM EMERGENCY CERTIFICATES

One other aspect of this proceeding in Docket No. R-389-B on which I feel compelled to comment, is our order of September 9, 1974, reinstating, *inter alia*, limited term certificates. I agreed that order, but in reviewing it, I noted that we completely failed to define what we meant by the word *limited*. As written it would appear that Opinion 699-B would allow limited terms to extend as long as 10, 15 or even 20 years.

Long term certificates with pregranted abandonments have been held illegal in the Moss case (Moss v F.P.C., D.C. Cir. 1974).

Limited term certificates are a form of pregranted abandonment. In addition, limited term certificates are only justified under our emergency procedures. By definition, I do not believe limited term comtemplates certificates of long duration. They can only be justified by our ability to predict the future public interest within reasonable limits as to the duration of the emergency. In Order 699-B itself, the majority stated, "We believe that these procedures should be reinstated with certain modifications in order that the interstate pipelines will be able to negotiate the additional short-term supplies of natural gas necessary to meet the demand for the 1974-5 winter season."

From that quote it appears their intent was clearly that limited term certificates were meant to meet the needs of an immediate emergency and not as a device to avoid applying for long-term sales under standard certificating procedures.

While I have agreed that limited term agreements do not have a place in providing better service during an emergency shortage, I also believe that they must, be limited in term to the coming year or at most, to the immediate and following winter. I also believe that limited term certificates should be granted only in those cases where real proof is presented that there is a reason other than hopes for a higher future price to limit the duration of the contract. The stated reason for granting limited term certificates was to divert intrastate gas to the interstate market. Where there is no true diversion, but only the avoidance of a true commitment to interstate commerce, I do not believe we should approve such applications.

In addition, I would amend Opinion 699–B to provide that emergency term means what it says and will be granted for no longer than 18–month periods as a maximum.

BIENNIAL REVIEW TO BEGIN JANUARY 1, 1975

Basically, I believe the 699 approach is valid in setting a national rate. On January 1, 1975, we will have the chance to make any needed changes in procedure or methodology. That is the time to begin any new pricing approach.

William L. Springer, *Commissioner*.

OPINION NO. 699–H

JUST AND REASONABLE NATIONAL RATES FOR SALES OF NATURAL GAS FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973—DOCKET NO. R–389–B

(December 4, 1974)

SMITH, Commissioner, *concurring in part* and *dissenting in part:*

I concur in the Opinion on Rehearing with the exception of the portion that grants the 699 rate to gas that is subject to expiring contracts. I dissent specifically and exclusively to the inclusion of those sales described in new Section 2. 56a(2)(iii) (Opinion 699–H, p. 76) among sales eligible for the Base National Rate. I regard for the 699 rate as mutually independent,[1] each requiring independent support.

I. THE RATE FOR "NEW" GAS

The discounted cash flow (DCF) analysis is an indispensable element in deriving a new gas rate that will be adequate to induce and compensate for the level of exploration and development that will be necessary to maintain the supply stability of interstate pipeline companies.

In contrast to the unadjusted *Permian I* formula, the DCF analysis here utilized results in the allowance of a return on the total investment in exploration and development, including dry hole cost. If a return on the dry hole portion of the investment is not allowed, the producer is required to write off there costs on a current-year basis against flowing-gas or other income. Unless such income was actually earned in that year, these costs must be written off as a loss. While most producers probably do and will continue to "expense" the exploration and development cost for tax purpose, it is patent that tax benefits are not the equivalent of actual income from the return on investment. Proper accounting for tax purposes is not necessarily proper accounting for ratemaking purposes.[2]

The effect of denying the return on the dry hole portion of exploration and development cost has been to favor large producers in the industry who have large and relatively stable quantities of flowing gas and to disfavor the smaller producers who likely have more erratic discovery and production patterns. Disadvantaged most by the approach is the new entrant who has

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[1] The framework established in Opinion No. 699 postulates the determination of a national rate for gas from wells commenced after January 1, 1973, and for gas first sold in interstate commerce after that date. The rate set purports to provide a fully adequate incentive for exploration, development, and production of new supplies. If the new gas rate provides adequate stimulation for new supply additions, then clearly no allowance of the new national rate for expiring contracts is justified. If the new nationwide rate in Opinion No. 699 is inadequate, then the remedy lies with adjustment of the nationwide rate level rather than in atoning for real or suspected inadequacies in that rate by granting the new price for the expiring contracts.

[2] *Alabama-Tennessee Natural Gas Co.* v. *F.P.C.*, 359 F.2d 318, 336 (5th Cir. 1966), *cert. denied*, 385 U.S. 847, *reh. denied*, 385 U.S. 964 (1966).

no flowing gas to look to for the "expensing" of initial exploration and development costs and who must, therefore, absorb as a net loss the time value of the investment costs that cannot be expensed. The years of adherence to the methodology have, in my view, contributed significantly to concentration in the industry.[3] Finally, the *Permian I* approach offers even the large producers no incentive to increase exploration above the level that can be funded from the flowing gas allowance.

The Commission recognized at the outset that there might be something awry with the methodology. In the *Permian I* opinion it stated: "However, capitalization of E&D may well be a useful approach and we do not foreclose in succeeding cases further consideration of this alternative method of costing. . ."[4]

Perhaps in an attempt to compensate for the inadequacies of the basic methodology, the Commission in *Permian I* included in the gas price a curious increment entitled "Adjustment for Exploration in the Excess of Production." The purpose of this increment was said to be to "encourage a level of exploratory effort which will continue to provide for findings in excess of production."[5] However meritorious the allowance may have appeared, it was falsely premised in the context of new gas costing. The premise was that desired and anticipated overall increases in exploration and development expense. That premise was not proven and in fact probably was not true during the 1960's. As an increment to new gas revenues, the allowance was only a rather crude method of giving producers additional cash flow that presumably could be spent for additional exploration and development.[6] While the increment was perfectly conceived and rationalized, the objective of stimulating a higher level of exploration and development was and is valid and is today all the more essential. The new gas price must fully cover the costs of finding new gas for it is only thereby that discrimination against new entrants and smaller producers can be avoided. Adherence to the unadjusted *Permian I* formula fails to achieve this objective. Adjusting the results obtained under that methodology by reference to the DCF analysis achieves a much more realistic cost-related incentive for producers to engage in expanded exploration and development.

The Opinion on Rehearing here issued properly recognizes trends in establishing the major production cost factors, successful well cost and dry hole costs per foot. Statistical analysis establishes a high correlation between the passage of time and cost per foot for successful wells and dry holes. The correlation coefficient between time and successful well costs for the past ten years is .98, and between time and dry hole costs for the same period is .95. Observation of general economic trends from 1972 to 1974 compels some adjustment of the 1972 data be made for the purpose of establishing 1973 and 1974 rates. Trending may not precisely predict the future, and in fact is likely to understate actual costs in a time of exceptionally high inflation. Also there can be dispute about the series chosen to develop the trend. Nevertheless, actual data will not be available hereafter for years for which rates are set

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[3] Between 1962 and 1972, the 25 laregst producers of natural gas for the interstate market increased their share of total sales by domestic producers to interstate pipelines from 70.9 percent to 76.7 percent and their share of total revenues from 73.1 percent to 78.2 percent. Producers selling less than 10 million Mcf a year to the interstate market accounted for 18.4 percent of total domestic sales to interstate pipelines in 1962 and 12.4 percent in 1972. (*Sales by Producers of Natural Gas to Interstate Pipeline Companies*, FPC, 1962 and 1972.)

[4] *Permian Basin Area Rate Proceeding*, 34 F.P.C. 159, 193 (1964), *affirmed*, *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

[5] *Ibid.* Subsequent events show that the allowance failed to achieve its purpose.

[6] The increment was deleted from the costing methodology in the *Texas Gulf Coast Area* opinion. Area Rate Proceeding, et al. (Texas Gulf Coast Area), 45 F.P.C. 671 (1971), *reversed*, *Public Service Commission of the State of New York* v. *FPC*, 487 F.2d 1043 (D.C. Cir., 1973) *cert. granted, vacated and remanded*, *Shell Oil Co.* v. *Public Service Commission of the State of New York*, 42 U.S.L.W. 3686 (U.S. June 17, 1974).

in this nationwide rate series and reasonable cost adjustments must be made Trending by regression analysis is a sound method of adjusting actual data within a reasonable tolerance.

II. THE RATE FOR "FLOWING" GAS

A. Applicability of the rate established in biennial reviews

I concur that it is proper to provide that the prices established in the biennial reviews will be applicable to the gas that is first delivered during the proceeding biennium. This is necessary to avoid the undesirable disruption in supply caused by speculation by the producer through suspension of drilling or withholding if supplies near the end of each biennium. However, at some time in the indefinate future, if the cost increases continue, the disparity between new prices and old prices will be large enough to outweigh the desirability of suppressing end term speculation. At that time, only the new gas should be given the newly determined price. In other words, year-by-year of biennium-by-biennium "vintaging" is not *per se* a sound policy, but vintaging by cost groupings ultimately will become necessary to preclude the exaction of excessive and unjustifiable economic rent from flowing gas.

B. New gas rate for contracts with expired primary terms

The excessive and inadequately supervised economic rent and the discriminatory and anticompetitive impact cause my dissent to the portion of the Opinion that awards the new gas rate to flowing gas that is the subject of expiring contracts.[7] There are procedural issues raised by that application of this rate. Such a proposal was never noticed in conjunction with the R–389 proceeding. Further, a strong inference that R–389 would not deal with flowing gas can be derived from the notice in the R–478 proceeding which is stated to pertain to gas from "wells commenced before January 1, 1973."[8]

In addition, I perceived and stated substantive reservations to that portion of the Opinion in my concurrence to the initial Opinion No. 699. The immediate cost to the consumer is not balanced by an assured or even demonstrably likely future benefit. A more detailed analysis of the contracts on file with the Commission in the R–478 proceeding reveals that the aggregate cost to the consumer through 1981 could reach $2.6 bilion[9] and that analysis does not take account of any price increases that might be determined in future biennial reviews. The granting of the price increase to flowing gas is highly discriminatory to new entrants in the industry who enter with an unwarranted competitive disadvantage. Further, it is highly discriminatory among existing members of the industry. An analysis of the contracts on file with the Commission on the R–478 proceeding shows that the incidence of volumes under contracts expiring between 1972 and 1980 varies widely between producers.[10] For some producers, 100% of the 1972 volumes are subject to contracts that will expire before 1980. For other producers, less than 10% of the 1972 volumes would be eligible for the new gas rate prior to 1980. The other producers are spaced widely between the extremes. Such varying impact reinforces my view that the allowance of the new gas rate to expiring contracts is not a reasonable method of providing internal financing for producers nor is it consistent with the public interest.

Finally, Opinion 699 rejected the DCF analysis in part because the increase in flowing gas could make up inadequacy of the return element in the basic new gas rate.[11] However, the adoption of the DCF analysis in the present

[7] § 2.56a(a)(2)(iii), Opinion No. 699–H, at p. 76.

[8] Nationwide rulemaking to Establish Just and Reasonable Rates for Natural Gas Produced From Wells Commenced Before January 1, 1973, Docket No. R–478, (May 13, 1973).

[9] See Appendix A.

[10] See Appendix B.

[11] Opinion 699, pp. 89–90 (June 21, 1974).

Opinion places new gas costing on an independent footing and that justification for increasing the following gas price to existing producers in this proceeding thus is no longer present.

I would approve an increase in flowing gas to the rates established in this proceeding only of preceded by public notice and subject to a plan and conditions that would improve the bargaining position of the interstate pipelines for on-shore gas. The interstate piplines are rapidly losing ground to an intrastate market on on-shore areas, a fact that is not surprising in view of intrastate market price for new gas substantially higher than that price allowed for interstate purchases. The Commission should consider a plan allowing a producer to escalate the price of flowing gas sold to a given pipeline to the 699 rate to the extent of one, or possibly two, Mcf of flowing gas for each Mcf of new gas that is sold to pipeline buyers from on-shore areas under a new contract each year. Such a plan might slow down, although probably not reverse, the negative trend in on-shore dedications to the interstate market. If the flowing gas escalations were so conditioned, the consumer would at least have the assurance that an increase in price being paid for flowing gas was compensated for in the form of a new supply from the on-shore area. Such an escalation program is not free from difficulty or discrimination, but I tentatively believe it to be far more consistent with the public interest than the unconditional price increase in flowing gas that is granted by the Majority.

The awarding of the 699 rate to the gas that is subject to expiring contracts sets the pricing system on a course that, if followed by future Commissions, would eliminate vintaging for all gas except that which is subject to life-of-lease or reservoir contracts. In affirming the Commission's Opinion 639, the Fifth Circuit Court of Appeals forewarned:

"We do not reach the question of whether the FPC may altogether discontinue the use of vintaging. Rather in each future order the Commission must continue to produce substantial evidence to support each essential element of the proposed rate structure. In Re Permian Basin Rate Cases, *supra*. Certainly the absence of presence of vintaging must be regarded as an essential element." [12]

I do not find substantial evidence that supports the nationwide, albeit gradual, discontinuance of vintaging that is herein approved by the Majority.

DON S. SMITH, *Commissioner.*

APPENDIX A.—SUMMARY OF ESTIMATED INCREASED REVENUE IMPACT OF OPINION NO. 699 BY ALLOWING THE NEW GAS RATE FOR CONTRACTS WHOSE PRIMARY TERM EXPIRES

Year	1st eligible in prior years on full year basis		1st eligible in current year on full year basis		Total volume [1]	Total revenue [2]	
	Volume [1]	Revenue [2]	Volume [1]	Revenue [2]		Annual	Cumulative
1974			381	127.2	381	127.2	127.2
1975	323	111.3	175	61.7	499	173.0	300.2
1976	425	152.1	120	43.1	545	195.2	495.4
1977	463	170.8	285	100.9	748	271.7	767.1
1978	636	238.0	282	107.1	918	345.1	1,112.2
1979	778	300.7	347	130.7	1,125	431.4	1,543.6
1980	958	377.7	383	143.5	1,342	521.2	2,064.8
1981	1,140	455.6	261	105.1	1,402	560.7	2,625.5

[1] Billion cubic feet.
[2] Millions of dollars.

NOTES

1. Volumes represent an expansion of volumes reported to an estimated 100 percent.
2. Volumes for 1974 and subsequent years reflect an assumed 15 percent per annum decline in deliverability.
3. The assumed base rates reflect weighted average tax inclusive ceiling rates with 1 cent annual escalation.

Source: Docket No. R-478; questionnaire schedule No. 5.

[12] *Shell Oil Co.* v. *F.P.C.*, 491 F.2d 89–90 (5th Cir., 1974).

APPENDIX B.—PERCENTAGE OF REPORTED 1972 SALES VOLUME UNDER CONTRACTS WHOSE PRIMARY TERM WILL EXPIRE THROUGH 1980 (50 COMPANIES FOR WHICH DATA ARE AVAILABLE)

Producer	Reported 1972 volumes (thousand cubic feet)	Volumes under contracts expiring through 1980	
		Volumes (thousand cubic feet)	Percentage of 1972 volumes
Amerada Hess	63, 485, 059	24, 167, 887	38. 069
Amoco Production	952, 954, 209	313, 344, 463	32. 881
Atlantic Richfield	700, 141, 841	293, 711, 390	41. 950
Austral Oil	37, 428, 766	3, 048, 805	8. 146
Aztec Oil & Gas	34, 552, 170	21, 504, 000	62. 236
Belco Petroleum	25, 355, 527	23, 524, 354	92. 817
Beta Development	5, 570, 178	5, 520, 178	100. 000
Champlin Petroleum	119, 169, 504	78, 723, 089	66. 060
Chevron Oil	46, 752, 951	21, 447, 009	45. 873
Cities Service Oil	361, 732, 338	100, 963, 152	27. 911
Clinton Oil	17, 019, 943	5, 919, 877	34. 782
Coltexo Corp	2, 995, 682	2, 291, 916	76. 507
Continental Oil	447, 149, 053	221, 401, 009	49. 514
Diamond Shamrock Corp	73, 007, 874	5, 357, 447	7. 338
Exchange Oil & Gas	21, 375, 951	723, 789	3. 386
Exxon Corp	1, 172, 988, 649	466, 460, 824	39. 767
General American Oil	83, 513, 440	38, 259, 227	45. 512
Getty Oil	330, 760, 251	218, 224, 473	65. 977
Gulf Oil	718, 923, 410	166, 722, 685	23. 191
Helmerich & Payne	11, 410, 776	1, 068, 751	9. 366
Hassie Hunt Trust	18, 236, 327	5, 288, 432	28. 999
Hunt Oil	45, 557, 544	4, 812, 684	10. 564
Kerr-McGee Corp	147, 549, 256	43, 210, 163	29. 285
LVO Corp	10, 785, 271	103, 007	1. 001
Lone Star Producing	17, 194, 279	3, 574, 117	20. 787
Louisiana Land & Explor	51, 574, 132	3, 731, 728	7. 236
MAPCO, Inc	19, 417, 787	2, 194, 729	11. 303
Marathon Oil	92, 500, 461	26, 606, 648	28. 764
Mobil Oil	616, 510, 689	96, 144, 964	15. 595
Monsanto Co	64, 598, 922	34, 515, 415	53. 430
Northern Natural Gas Prod	56, 622, 983	406, 192	. 717
Pennzoil Producing	165, 005, 765	68, 171, 178	41. 314
Placid Oil	41, 128, 027	14, 464, 107	35. 168
Pubco Petroleum	11, 594, 463	8, 021, 242	69. 182
River Corp	8, 864, 487	7, 860, 567	88. 675
Shell Oil	654, 146, 923	205, 738, 729	31. 451
Sohio Petroleum	58, 447, 856	13, 241, 579	22. 655
Southern Natural Gas Co	14, 725, 463	1, 184, 200	8. 042
Southern Natural, joint venture	14, 970, 204	14, 970, 204	100. 000
Stephens Production	6, 422, 222	5, 286, 561	82. 317
Sun Oil	296, 497, 642	119, 791, 628	40. 402
Superior Oil	250, 307, 281	113, 832, 085	45. 477
Sylvania Corp	2, 122, 476	890, 481	41. 955
Tenneco Oil	14, 615, 826	4, 205, 176	28. 771
Terra Resources	11, 082, 811	3, 323, 834	29. 991
Texaco, Inc	567, 583, 743	119, 861, 819	21. 118
Texas Gas Exploration	35, 444, 182	1, 988, 888	5. 611
Texas Oil & Gas	12, 246, 306	1, 946, 582	15. 895
Trans Ocean Oil	20, 456, 550	6, 569, 238	32. 113
Warren Petroleum	90, 351, 365	15, 932, 448	17. 634
Total reported	8, 642, 848, 815	2, 960, 318, 010	34. 251

Source: Docket No. R–478; questionnaire schedule No. 5.

OPINION NO. 699–H

JUST AND REASONABLE NATIONAL RATES FOR SALES OF NATURAL GAS FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973—DOCKET NO. R–389–B

(December 4, 1974)

MOODY, Commissioner, *dissenting:*

I dissent to the prescription of a rate which will have no more effect than the application of a bandaid to a severed jugular vein.

I

While I am gratified that some of my views on cost-trending[1] and true yield analysis[2] have now achieved majority acceptance, with a resultant admission by the majority that it understated costs[2a] by at least 20 percent in Opinion No. 699, the fundamental error, of setting a rate level which will not return costs and which ignores noncost considerations, remains.

I do not suggest that recognition of a 20 percent error in costing is insignificant, nor do I pretend that a recalculation of rates to move from 42¢/Mcf to 50¢/Mcf will not achieve some good results. The consumer will benefit from the larger number of offshore gas prospects that are made economically accessible by a higher rate. No, Opinion No. 699–H is much superior to Opinion No. 699.

Having said this, however, and having commended the majority for correction of two of the more egregious errors of Opinion No. 699, it is still incumbent upon me to say that Opinion No. 699–H fails to establish a just and reasonable rate.[3] The interstate consumer, already deprived of a reliable and adequate supply of natural gas in most sections of the country,[4] will not be given succor by a 50¢ rate, nor will that rate greatly lessen the economic disruptions inherent in curtailment of pipeline service.[5] The gas shortage is a grievous wound inflicted on the economic life of America by this Commission; to heal that wound, far more than the majority's action is demanded.

II

The majority's rate prescription, judged by the standards of traditional costing methodology and without regard to modifications or improvements in that methodology, continues to understate producer cost. The 50¢/Mcf rate will not return the costs resonably to be anticipated for the 1973–1974 biennium.

The errors which remain are holdovers from Opinion No. 699. I refer, of course, to the majority's continued refusal to follow the undisputed record before us with respect to productivity and an allowance for income tax expense.

Both issues were fuly addressed in my original dissent,[6] and there is no reason to repeat what was there stated. I adhere to the view that a prediction

[1] See my dissent to Opinion No. 699, at pp. 10–21. I there argued for trending of cost components in order to achieve a more rational relationship between future cost levels and a rate designed for future applicability. The majority now concedes that trending of drilling costs, successful and dry hole, is both appropriate and necessary. The majority still refuses, however, to acknowledge that the lease acquisition cost component assigned in a 50¢/Mcf rate bears no relationship whatsoever to the record before us.

[2] In my dissent to Opinion No. 699, at pp. 34–43, I advanced the belief that a failure to provide a return on total invested capital precluded the producer from earning the rate of return found to be essential to a viable enterprise. The majority's acceptance of DCF analysis recognizes the validity of this criticism. The method of DCF analysis displayed here—as to timing and tax assumptions—can no doubt be improved and refined, and our next national rate proceeding will unquestionably benefit from specific comments in this regard.

[2a] I use "costs" in the same context as the majority. It should always be borne in mind, however, that the Commission does not determine actual costs for any producer or for any sale. To the contrary, the Commission develops a hypothetical rate base, hypothetical costs, and a hypothetical rate of return on the basis of industry-wide averages.

[3] The rate prescribed by the majority is still predicated on the assumptions—wholly unsupported by the record—that 1973–1974 costs will, in total, drop below the level of the preceding four years, and that 1973–1974 productivity will exceed that of the previous four years. The legal infirmities of ratemaking based on fantasy and not on fact were discussed at pp. 2–34 of my original dissent. There is no reason to alter my assessment of the record, or to restate my views. I stand on the dissent as written, for a 50¢ rate is no less subject to attack than a 42¢ rate on the basis of the record.

[4] During September, 1973, through August, 1974, nineteen interstate pipelines were forced to curtail their firm customers a total of 1.361 trillion cubic feet. See FPC News Release No. 20849, issued November 15, 1974, summarizing BNG study of curtailments.

[5] The District of Columbia Court of Appeals has recently written a graphic description of the havoc wreaked by pipeline curtailment on one system where the curtailment level is approaching 28 percent. See *per curiam* slip opinion issued November 26, 1974, in No. 73–1999 *Consolidated Edison Co. of N.Y. v. F.P.C.* The situation on the *Transco* system there dealt with will be repeated on other systems as the shortage deepens.

[6] See dissent, pp. 5–10, 13–29, and 29–33 for discussion of these specific issues. As already noted in footnote 3, *supra*, the movement from 42¢/Mcf to 50¢/Mcf does not resolve the basic problem of a rate based on assumptions and estimates not supported by the record.

of productivity which cannot be supported by the record evidence renders the rate based thereon unlawful.

In addition, however, to the matters discussed in the original dissent, the means are at hand to demonstrate the error of the majority. Since Opinion No. 699 was issued on June 21, 1974, the results of gas well drilling for calendar year 1973 have become available.[7] We now know that in 1973 the following occurred:

	Million cubic feet
Successful gas well footage (World oil)	32, 973, 994
Successful gas well footage (AAPG)	35, 587, 012
Total gas reserves added	3, 716, 930

Thus the productivity *actually experienced* in 1973 was 113 Mcf/ft, based on World Oil reported footage and 104.4 Mcf/ft, based on AAPG reported footage.

While Opinion No. 699–H continues to reflect a productivity prediction of 485 Mcf/ft. as the basis of 1973–1974 rates, it is now tragically clear that my dissent has been proven to be correct. 485 Mcf/ft. is not a rational prediction based on evidence and it cannot stand.

While I can understand, and sympathize with, the natural human reluctance of my colleagues to admit error in yet a third respect, thereby further validating the original dissent to Opinion No. 699, I think it irresponsible for the majority to ignore 1973 results and pretend that they are not now of record. At the very least, if the majority is to adhere to a seven-year averaging technique for predicting productivity, they should include the most recent year's results in their calculations.

Why do they not? Simply because this one change—and this only serves to underscore the sensitivity of the productivity prediction—drastically alters the cost estimates underlying the majority's 50¢/Mcf rate. A simple change, to substitute 1973 productivity for 1966 productivity, is *necessary* to the majority's theory that the average of the most recent seven years is the most reliable means of predicting the next two years' productivity; if this change is made, it is clear that a 50¢ rate *will not return costs.*

I have labored at comprehension of the reasoning set forth at pp. 19–26 of Opinion No. 699–H wherein the majority tries to justify setting a rate for 1973–1974 on the assumption that a six-year trend in declining productivity will be suddenly reversed. I glean that the majority believes that recently expanded drilling efforts will add greater reserves and that, therefore, anticipation of higher productivity is reasonable. I submit that this reasoning will not hold water. *First,* 1973 was one of those expanded drilling years that the majority is looking to for new reserves. But 1973 drilling resulted in the lowest productivity on record. *Secondly,* more drilling may reasonably be expected to produce additional reserves, but productivity does not increase unless the *ratio* of reserve additions to drilling increases. The greater the footage drilled, the more reserves are needed to hold productivity constant. The majority's conclusion that greater drilling efforts necessarily presages an improvement in reserves added per foot drilled is simplistic; it is nothing more than wishful thinking insofar as the record before us is concerned.

III

The perpetuation of demonstrable flaws in the majority's cost-estimation analysis[8] present a court with a traditional problem of judicial review of administrative action. In contrast, the majority's continued refusal to assess the effects of its rate order, and measure the legality thereof in terms of supply and demand consequences, presents the same type of problem faced by the

[7] See Table I attached by the majority to Opinion No. 699–H.

[8] In my original dissent I sought only to show that the majority had no substantial evidence support for its rate, even assuming the legality and propriety of the cost estimation—rate setting methods followed. Part II, *supra,* of this dissent pursues the same approach.

Fifth Circuit in reviewing *SoLa I.*[9] The Court there saw what the Commission did not—that the mechanical application of cost-estimation formulae in natural gas pricing was resulting in the constriction of supply, to the detriment of consumer and producer alike.

Following *Austral's* insistence that the Commission weigh more carefully the effects of its rate orders, the Commission made a modest turn to incentive ratemaking. In *SoLa II*[10], *Other Southwest*[11], and *Texas Gulf Coast*[12], noncost factors were considered and utilized. Despite vociferous attacks, the Commission was upheld in doing so.[13] Now, however, when it is more critical than ever that the Commission fulfill its statutory duty to call forth adequate, reliable gas supplies, the majority has retreated into the shell of 100 percent cost based rates. The ratemaking tools necessary to combat the gas shortage have been discarded.

The majority's Opinion on Rehearing is the legal equivalent of a final denial by the Commission of any responsibility for whether or not its rate order will permit the movement of adequate and reliable supplies of gas to the interstate market. I believe this abdication of responsibility is correctable upon judicial review.

It is my hope that the Courts reviewing this order will speak definitively on the powers—and duties—of the Commission to set rates reasonably calculated to bring to interstate gas consumers a reliable and adequate supply of natural gas. For my own part, I believe that is the mandate already issued to the Commission by the Act and by judicial interpretation thereof.[14] By a majority of the Commission is of the unshakeable persuasion that rates exceeding cost estimates are unlawful—that, even though the devastating effects of cost-based rates on the consuming public are clearly identifiable, the Commission is powerless to do aught but perpetuate tht underlying theory of *Permian I* ratemaking. These colleagues with whom I differ are men of good faith and men of intelligence. Perhaps they are right; perhaps the Courts fully intend to restrict rates to the level of costs plus return.[15] If so, then let it be said. Then at least we will know that the Commission should *not* worry about supply elicitation when it promulgates a rate order.

Though I realize it is presumptuous, I ask that a reviewing Court speak to what is *required* of the Commission in the performance of producer ratemaking functions, and not what is permissible. Without specific direction, I have little hope that the Staff of the Commission, or a majority of the Commissioners, will do more than follow the politically popular course—of restricting rates to the level of estimated costs.

In my original dissent to Opinion No. 699, I opined that a reviewing court would probably not compel major changes in the Commission's ratemaking theories. I have changed my views; if the Court does not now interpose its judgment, there is no realistic hope for the interstate gas consumer. What we have here is an agency which believes itself so fettered by the *City of Detroit*[16] dictum concerning costs that it issues an order which it knows cannot significantly lessen the gas shortage. Judicial direction is absolutely imperative if gas consumers are to be protected.

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[9] See 40 FPC 530 (1968)—the first area rate decision for *Southern Louisiana.* On appeal, in *Austral Oil Co.* v. *F.P.C.,* 428 F.2d 407 (CA 5, 1970) cert. denied, 400 U.S. 950 (1970), the Court faced squarely the Commission's failure to give adequate consideration to the effects of its order, and while affirming the Commission, did so in language unmistakable: The Commission had failed in its responsibilities.

[10] Opinion No. 598, 46 FPC 86 (1971).

[11] Opinion No. 607, 46 FPC 900 (1971).

[12] Opinion No. 595, 45 FPC 674 (1971).

[13] *Mobil Oil* v. *F.P.C.,* 42 U.S.L.W. 4842 (June 10, 1974); *Shell Oil Co.* v. *F.P.C.,* 484 F.2d 469 (CA 5, 1973), cert. denied 42 U.S.L.W. 3688 (1974).

[14] See pp. 44–46 of my original dissent.

[15] Certainly the rationale of the Court in the *Texas Gulf Coast* appeal [see 487 F.2d 1043 (CADC, 1973)]; in the *Belco* appeal; and in the *George Mitchell* appeal clearly indicates that one Court of Appeals believes producer costs are the be-all and end-all of ratemaking.

[16] *City of Detroit* v. *F.P.C.,* 230 F.2d 810 (1955) cert. denied 352 U.S. 829 (1956).

IV

I file this dissent—overlong and didactic as it is—because of a sense of profound concern for the present, and future, of the gas consumer dependent on the interstate pipelines. I attempt hereby to bring to the attention of the reviewing Court the message of catastrophe which current figures portend.

The basic data is known to us all:

1963–73 DOMESTIC RESERVES, PRODUCTION AND PURCHASES OF MAJOR GAS SUPPLY COMPANIES [1] (FROM FORM 15 REPORTS)

Year	Number of companies	Annual production and purchases	Yearend gas reserves
1963	24	9.0	184.6
1964	24	9.7	185.0
1965	23	10.0	187.6
1966	24	10.8	190.0
1967	24	11.5	194.1
1968	24	12.2	191.3
1969	24	13.1	184.2
1970	25	13.8	170.1
1971	25	13.9	158.1
1972	25	13.9	144.2
1973	25	13.4	131.9

[1] Major companies are those having over 900 billion cubic feet of domestic in-the-ground reserves at the inception of the form 15 report or date of 1st filing of the form.

The pattern of near-constant production and declining year-end reserves occurs because new reserves are not being added at a sufficient rate to offset deliverability declines from old reservoirs. The pattern of reserve additions compared to natural gas production is set forth below:

RESERVES, PRODUCTION, AND RESERVE ADDITIONS OF INTERSTATE PIPELINES, FORM 15 DATA (LOWER 48 STATES)

[Volumes in trillions of cubic feet]

	End of year reserves	Net production	Net reserve additions
1963	188.5	9.4	N/A
1964	189.2	10.0	10.7
1965	192.1	10.4	13.3
1966	195.1	11.1	14.1
1967	198.1	11.8	14.8
1968	195.0	12.6	9.5
1969	187.6	13.4	6.1
1970	173.6	14.1	0.04
1971	161.3	14.2	1.9
1972	146.9	14.2	(0.2)
1973	134.3	13.7	1.1

Thus, for six consecutive years, the interstate system has eaten away at existing reserves. The inventory is fast disappearing from the shelf, as indeed it must when production consistently exceeds new reserve additions. What is being consumed is not being replaced.

For a few years, inventory consumption can be tolerated without significant impact. But we have had those few years. They are behind us. The repeated failure to balance new supply and production has taken its toll, and we now see the vast majority of the pipelines unable to meet the needs of their customers. Thus we find:

COMPARISON OF ACTUAL FIRM REQUIREMENTS AND FIRM CURTAILMENTS FOR YEAR SEPTEMBER 1973 THROUGH AUGUST 1974 WITH PROJECTIONS FOR YEAR SEPTEMBER 1974 THROUGH AUGUST 1975 (FROM BNG REPORT OF NOV. 15, 1974—SEE FPC NEWS RELEASE NO. 20849)

Pipeline	Total for year September 1973–August 1974, actual			Total for year September 1974–August 1975, projected		
	Firm requirements (million cubic feet)	Volume curtailed (million cubic feet)	Percent curtailed	Firm requirements (million cubic feet)	Deficiency (million cubic feet)	Percent deficient
Alabama-Tennessee Natural Gas Co.	26,558,000	0	0	29,863,000	0	0
Algonquin Gas Transmission Co.	160,995,000	10,475,000	6.51	162,648,000	12,205,000	7.50
Arkansas Louisiana Gas Co.	535,062,000	162,018,000	30.28	538,692,000	157,302,000	29.20
Cities Service Gas Co.	561,668,000	49,187,000	8.76	577,183,000	131,319,000	22.75
Colorado Interstate Gas Co.	369,430,000	69,000	.02	370,300,000	0	0
Columbia Gas Transmission Corp.[1]	1,345,959,000	----------	----------	1,457,559,000	216,011,000	14.82
Commercial Pipeline Co., Inc.	373,000	0	0	401,000	0	0
Consolidated Gas Supply Corp.	704,628,000	0	0	779,492,000	43,756,000	5.61
East Tennessee Natural Gas Co.	98,205,000	0	0	81,300,000	3,459,000	4.25
Eastern Shore Natural Gas Co.	11,187,000	42,000	.37	(2)		
El Paso Natural Gas Co.[3]	1,437,793,000	124,691,000	8.67	1,453,441,000	291,019,000	20.02
Florida Gas Transmission Co.	28,521,000	0	0	38,940,000	0	0
Great Lakes Gas Transmission Co.	415,806,000	0	0	424,970,000	0	0
Kansas-Nebraska Natural Gas Co.	85,377,000	0	0	83,656,000	0	0
Kentucky-West Virginia Gas Co.	26,522,000	0	0	27,585,000	0	0
Lawrenceburg Gas Transmission Corp.	5,414,000	0	0	5,475,000	0	0
Louisiana-Nevada Transit Co.	4,813,000	56,000	1.16	4,787,000	523,000	10.93
McCulloch Interstate Gas Corp.	15,230,000	0	0	10,969,000	0	0
Michigan Wisconson Pipe Line Co.	935,356,000	0	0	937,562,000	0	0
Mid Louisiana Gas Co.	31,225,000	0	0	32,572,000	4,226,000	12.97
Midwestern Gas Transmission Co.	347,927,000	0	0	350,011,000	9,003,000	2.57
Mississippi River Transmission Corp.	202,898,000	2,466,000	1.22	210,316,000	926,000	.44
Montana-Dakota Utilities Co.	35,584,000	0	0	38,439,000	0	0
National Fuel Gas Supply Corp.[4]	99,752,000	0	0	167,436,000	0	0

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Natural Gas Pipeline Co. of America	1,192,732,000	213,133,000	17.87	1,204,529,000	216,479,000	17.97
North Penn Gas Co	28,573,000	0	0	29,834,000	0	0
Northern Natural Gas Co	817,516,000	8,547,000	1.05	815,698,000	5,885,000	.72
Northwest Pipe Line Corp.[3]	246,923,000	11,230,000	4.55	453,588,000	40,738,000	8.98
Pacific Gas Transmission Co	402,964,000	0	0	415,845,000	0	0
Panhandle Eastern Pipeline Co	814,134,000	48,677,000	5.98	834,520,000	87,170,000	10.45
South Georgia Natural Gas Co	10,839,000	0	0	13,942,000	0	0
Southern Natural Gas Co	597,643,000	0	0	645,850,000	2,501,000	.39
Tennessee Gas Pipeline Co., A Division of Tenneco, Inc.[5]	1,346,864,000	10,898,000	.81	1,368,970,000	104,364,000	7.62
Tennessee Natural Gas Lines, Inc	22,292,000	0	0	23,879,000	0	0
Texas Eastern Transmission Corp	1,073,319,000	146,198,000	13.62	1,085,960,000	247,162,000	22.76
Texas Gas Pipe Line Corp	4,377,000	0	0	2,129,000	0	0
Texas Gas Transmission Corp	731,735,000	14,229,000	1.94	771,081,000	64,639,000	8.38
Transcontinental Gas Pipe Line Corp	1,085,735,000	209,991,000	19.34	1,107,008,000	307,364,000	27.77
Transwestern Pipeline Co	365,012,000	24,616,000	6.74	366,852,000	98,875,000	26.95
Trunkline Gas Co	591,636,000	187,349,000	31.67	593,239,000	227,153,000	38.29
United Gas Pipe Line Co	1,563,743,000	552,582,000	35.34	1,608,438,000	704,350,000	43.79
Valley Gas Transmission, Inc	16,183,000	0	0	N/A		
West Texas Gathering Co	95,693,000	0	0	92,285,000	0	0
Western Gas Interstate Co	7,250,000	0	0	8,708,000	73,000	.84
Total	18,501,446,000	1,776,454,000	9.60	19,226,225,000	2,976,507,000	15.84
Less, pipeline to pipeline curtailments		414,583,000			618,402,000	
Net curtailments		1,361,871,000			2,358,105,000	

[1] Columbia Gas Transmission Corp. states that during the period November 1973 through March 1974, it imposed a 2 percent curtailment on all CD, WS, and G customers, however, due to warmer than normal weather, energy conservation, etc., actual curtailment cannot be ascertained.

[2] Eastern Shore Natural Gas Co. is uncertain about the curtailment by Transcontinental Gas Pipe Line Corp. to Eastern Shore, whether it will be 22 or 35 percent. It did not submit estimates for the projected period September 1974–August 1975.

[3] On Jan. 31, 1974, El Paso divested its Northwest Division system properties to Northwest Pipeline Corp. Northwest has filed actual data for February through August 1974. El Paso has reported the actual data for the period September 1973 through January 1974.

[4] National Fuel Gas Supply Corp. formerly United Natural Gas Co.

[5] Firm curtailments were added to firm deliveries to arrive at firm requirements in the Sept. 30, 1974 report.

NOTE.—N/A—not available.

The foregoing tabulation relates to curtailments of firm customers; as might be expected, interruptible customers have fared even worse, and can expect curtailments of 58.24 percent next year:

COMPARISON OF ACTUAL INTERRUPTIBLE SALES AND CURTAILMENTS FOR YEAR SEPTEMBER 1973–AUGUST 1974 WITH PROJECTED REQUIREMENTS AND DEFICIENCIES FOR YEAR SEPTEMBER 1974–AUGUST 1975

	Actual [1]			Projected [2]		
	Interruptible requirement (million cubic feet)	Volume curtailed (million cubic feet)	Percent curtailed	Interruptible requirement (million cubic feet)	Volume deficiency (million cubic feet)	Percent deficient
Alabama-Tennessee	14,996	3,222	21.48	16,472	3,569	21.66
Algonquin Gas	10,452	10,452	100.00	13,131	13,131	100.00
Arkansas-Louisiana	13,434	13,434	100.00	19,868	19,868	100.00
Colorado Interstate	49,305	18,363	37.24	60,865	33,925	55.74
East Tennessee	22,759	0	0	25,455	23,673	92.99
Eastern Shore	1,955	1,689	86.39	(4)		
El Paso [3]	0	0	0	0	0	0
Florida Gas	132,640	39,968	30.13	134,723	73,233	54.36
Kansas-Nebraska	32,546	0	0	30,390	1,350	4.44
Louisiana-Nevada	1,841	3	.20	6,243	2 972	47.61
Mississippi River	35,365	26,611	75.25	0	0	0
Montana-Dakota	21,220	256	1.21	21,145	330	1.56
Northern Natural	11,179	0	0	2,345	0	0
Northwest Pipeline [3]	14,778	5,949	40.26	26,991	24,654	91.34
Panhandle Eastern	69,851	14,692	21.03	65,087	26,705	41.03
South Georgia	29,604	13,403	45.27	29,602	17,263	58.32
Southern Natural	168,537	97,746	57.99	126,095	101,402	80.42
Tennessee Natural	14,354	1,783	12.42	15,353	2,878	18.74
Texas Gas	4,058	0	0	4,080	3,877	95.02
Transwestern	1,050	0	0	1,050	0	0
Total	649,894	247,571	38.09	598,895	348,830	58.24
Less, Pipeline to pipeline curtailments		29,262			82,625	
Net curtailments		218,309			266,205	

[1] Year September 1973–August 1974.
[2] Year September 1974–August 1975.
[3] On Jan. 31, 1974, El Paso divested its Northwest Division system properties to Northwest Pipeline. Northwest has filed actual data for February through August 1974. El Paso has reported the actual data for the period September 1973 through January 1974.
[4] Eastern Shore is uncertain about the curtailment by Transcontinental to Eastern Shore, whether it will be 22 or 35 percent. It did not submit estimates for the projected period September 1974–August 1975.

Source: BNG Report of Nov. 15, 1974—See FPC News Release No. 20849.

Massive curtailments by the interstate pipelines were inevitable, of course, once it became clear that the pipelines were unable to attach sufficient new reserves. The deteriorating supply position of the pipelines is fully documented by reviewing the applicable Form 15 data filed with us annually. Over the past ten years we see that the pipelines began 1964 with 184.8 Tcf in reserves:

	Reserves	Annual production	G/P ratio
1963 (yearend)	188.5		
1964 reserve changes	+10.640	10.014	1.06
1965	+13.282	10.370	1.28
1966	+14.190	11.137	1.27
1967	+14.751	11.820	1.25
1968	+9.453	12.552	.75
1969	+6.081	13.433	.45
1970	+.038	14.092	.00
1971	+1.991	14.205	.14
1972	−.229	14.207	.02
1973	+1.092	13.680	.08
1973 yearend	134.3		

Over this ten-year span, the pipelines' gross change in reserves was minus 52.7 Tcf—a drop of almost 30 percent—because of the extent to which production outstripped positive reserve changes. A GC/P Ratio of 1 tells us that the pipelines are holding a constant reserve position; a ratio greater than 1 indicates an improvement in supply, while a ratio of less than 1 warns of supply deterioration. For the past ten years, our major pipelines experienced a GC/P ratio of only .57.

As indicated, all of the foregoing relate to the known past. These figures do no more than tell us what all responsible observers of the natural gas situation have fully recognized—that there is a shortage of crisis proportions which is already inflicting a heavy toll on the economic well-being of the United States.

But what of the immediate future? I am convinced that the crisis has only begun; that, if today's order is not quickly reviewed and quickly corrected, the current level of economic disruption will be but a shadow of what lies ahead. The handwriting on the wall for the future is reasonably clear.

Reserve to production ratios give a gross estimate of the number of years that presently committed reserves will serve the market. While, in my judgment, a composite R/P ratio tends to mask the problems of individual pipelines, a declining trend in the national R/P ratio provides some insight into future problems. Accordingly:

R/P RATIOS

	Form 15	
	Major companies [1]	All companies
1965	18.7	18.5
1966	17.7	17.5
1967	16.9	16.8
1968	15.6	15.5
1969	14.0	14.0
1970	12.3	12.3
1971	11.5	11.5
1972	10.4	10.3
1973	9.8	9.8

[1] Pipeline companies whose in-the-ground reserves, company owned and contracted from independent producers, are in excess of (900 billion cubic feet).

Of far greater significance are the deliverability studies which we require of the pipelines on an annual basis as part of the Form 15 filings. These studies express the pipelines' best judgment as to future deliverability of presently attached reserves. The figures are shocking.

COMPARISONS OF COMPOSITE 5-YEAR DELIVERABILITY PROJECTIONS FROM YEAREND DEDICATED DOMESTIC GAS RESERVES

[Billion cubic feet at 14.73/in²a at 60° F.]

	Date of estimate				
	1969	1970	1971	1972	1973
Yearend reserves [1]	187,609	173,556	161,341	146,906	134,317
	Annual volumes scheduled: [2]				
Years:					
1969	[3] 13,433				
1970	13,872	[3] 14,092			
1971	13,929	14,281	[3] 14,205		
1972	13,814	14,170	13,743	[3] 14,207	
1973	13,651	13,863	13,287	13,633	[3] 13,680
1974	13,350	13,258	12,738	12,907	13,052
1975		12,469	12,054	12,007	12,346
1976			11,360	10,984	10,980
1977				10,029	9,993
1978					9,002
5-year total	68,616	68,041	63,182	59,560	55,383
Percent of yearend reserves	36.6	39.2	39.2	40.5	41.2

[1] 1971, 1972, and 1973 data includes reported emergency purchases.
[2] Annual volumes scheduled prior to 1972 estimates do not include companies with less than 50 billion cubic feet of in-the-ground reserves who, prior to 1972 were not required to file deliverability estimates.
[3] Actual volumes purchased and/or produced.

A drastic drop off in deliveries from presently attached reserves is imminent. The magnitude of the deliverability decline can perhaps best be appreciated by analyzing the decline in percentage terms:

DELIVERABILITY COMPARISONS, 1968-1973—ALL COMPANIES REPORTING ON FORM 15[1]

	Date of estimate					
	1968	1969	1970	1971	1972	1973
Largest volume scheduled [2] (billion cubic feet)	13,345	13,929	14,281	13,743	13,633	13,062
	Percent decline from largest volume					
Year:						
2	0	0	0.8	3.5	5.3	5.5
3	1.0	.8	3.2	7.3	[3] 11.9	[3] 15.9
4	2.2	2.0	7.7	[3] 12.4	19.4	23.5
5	3.4	4.2	[3] 12.7	17.4	26.4	31.1
6	5.8	7.6	18.2	22.6		
7	8.7	[3] 12.7	24.2	28.2		
8	[3] 11.7	18.0	29.2	35.6		
9	15.9	24.4	37.4	43.2		
10	21.7	33.3	45.0	49.5		
11	29.4	41.2	51.7	60.5		
12	37.3	48.6	57.6	65.0		
13	45.7	55.5	63.3	68.8		
14	53.5	61.4	68.2	73.8		

[1] Excludes companies with less than 50 billion cubic feet of in-the-ground gas reserves for years 1968 through 1971.
[2] First year volumes with exception of 1968–69 which are 2d year volumes.
[3] Year 10 percent occurs.

At current production levels, national curtailment is in the range of 15 percent. When production from currently attached reserves drops by 45 percent in only five years, the level of curtailment may well be too great for survival of the gas industry.

Leaving aside questions of what this supply decline will do to these former gas consumers who can no longer be served, at any price, the rate impact of declining deliveries on these consumers who continue to receive service will, in my judgment, be totally unacceptable to this nation. Even if we assume no increase in pipeline fixed costs over the next five years, and even if we assume retention of present pipeline depreciation rates, those customers who receive gas in the future face unprecedented increases in pipeline rates—increases which may be predicted because reduced volumes require a higher rate per unit delivered to recover fixed costs. For a representative group of pipelines, the deliverability decline for each forecasts the following rate impact.

REPRESENTATIVE MAJOR PIPELINE COMPANIES—UNIT IMPACT UPON COST RECOVERY OF CHANGES IN SALES VOLUMES

Line	Company	Cost of service [1] (thousands)	Projected sales volumes based upon deliverability [2] (trillion cubic feet)					Unit cost recovery per thousand cubic feet of sales (cents per thousand cubic feet)				
			1974	1975	1976	1977	1978	1974	1975	1976	1977	1978
1	Columbia Gas	$518,458	1.390	1.298	1.208	1.200	1.153	37.29	39.96	42.92	43.27	44.99
2	Consolidated	220,279	.648	.641	.646	.701	.660	33.98	34.37	34.08	31.43	33.39
3	El Paso (divested)	368,651	1.248	1.088	.947	.860	.775	29.55	33.90	38.93	42.88	47.60
4	Florida Gas	66,455	.133	.125	.116	1.107	.100	49.96	53.28	57.17	62.40	66.13
5	Michigan-Wisconsin	281,181	.836	.837	.835	.835	.773	33.64	33.61	33.68	33.68	36.36
6	Natural	371,967	1.049	1.006	.931	.843	.779	35.45	36.96	39.95	44.11	47.76
7	Northern	298,848	.815	.747	.665	.607	.553	36.68	40.01	44.95	49.21	54.01
8	Panhandle	178,642	.649	.607	.566	.524	.490	27.54	29.45	31.56	34.08	36.48
9	Tennessee	440,800	1.301	1.312	1.211	1.101	1.004	33.88	33.61	36.40	40.02	43.90
10	Texas Eastern	377,033	.834	.786	.739	.717	.694	45.21	47.96	51.07	52.58	54.30
11	Texas Gas	158,515	.722	.686	.641	.608	.552	21.96	23.11	24.72	26.08	28.70
12	Transco	304,015	.773	.675	.577	.487	.411	39.32	45.07	52.66	62.40	73.89
13	Transwestern	82,498	.322	.278	.254	.232	.211	25.59	29.97	32.51	35.49	39.05
14	Trunkline	157,039	.419	.363	.346	.309	.272	37.50	43.29	45.39	50.80	57.82
15	United	153,266	.967	.835	.756	.662	.569	15.85	18.37	20.27	23.16	26.93

[1] Cost of service data taken from latest rate increase filing and excludes variable costs, primarily purchased gas commodity costs.
[2] Sales volumes reflect deliverability projections adjusted for company use 'ost and unaccounted for.

To place in focus the potential rate of the present trend of gas supply deterioration, note these specifics:

	Cents per thousand cubic feet	
	1974	1978
El Paso	29.55	47.60
Natural	35.45	47.76
Northern	36.68	54.00
Tennessee	33.87	43.90
Texas Eastern	45.21	54.30
Transco	39.32	73.89
Transwestern	25.59	39.05
United	15.85	26.92

These figures should be compared with the majority's analysis of the potential rate impact on consumers by reason of increased wellhead rates (Opinion, pp. 54–56). It appears that increased curtailment may well cause a higher rate to consumers (for less gas), than will an increase in the price paid to producers.

The short-range impact of the pipelines' inability to meet the needs of their customers has other consequences. I have set forth at page 9, *supra*, the anticipated level of curtailment for September 1974–August 1975. These curtailments will cause a greater demand on oil products, which, tragically, can be met only through increased imports of foreign oil and porducts. The fuels necessary to substitute for 2.3 Tcf of nonavailable natural gas will approximate 387 million barrels of #2 fuel oil. For the longer range, if the projected decline in deliverability of natural gas—causing curtailments far in excess of 2.3 Tcf—is considered, it would seem obvious that the future fuel bills of this country, and the increased dependence on imported oil, are totally unacceptable.

Current levels of curtailment, at a national average of approximately 15 percent, have enormously disruptive. If the present procurement activities of the interstate pipelines are no more productive than they have been, the sharply accelerating deliverability decline which presages curtailment levels of 30 percent or more within the next five years, clearly predicts economic chaos and a total breakdown of the FPC's rationing efforts.

V

The majority's order will not prevent, nor materially lessen the grave consequences which lie ahead for the interstate gas consumer. I so conclude because of the unanimity of the parties before us in this proceeding who assert, without exception, that a rate based on costs alone—and falling within the range set by Opinion No. 699—will not permit the interstate pipeline to attach sufficient new reserves to reverse the trend of the past six years.

Pipelines and distributors alike now join the producing segment in analyzing the majority's rate order as ineffective. Even those parties not involved in buying and selling gas who say that a 42¢/Mcf rate is too high make their arguments only in context of producer profit levels; none assert that interstate consumers will, in fact, gain substantial new supplies under the majority's rate order.

The record before us wil not permit a reasonable man the luxury of belief that interstate pipelines can successfully contract for new onshore supplies of gas at the rate level set by the majority. What the majority has done is, for all practical purposes, set a rate for new offshore federal domain gas. Only those new supplies which must, by operation of law,[17] move interstate will move into interstate commerce under the rate structure set forth in Opinion No. 699–H. Onshore gas, which can be sold free of the price restraints of our juristdiction, and which can be marketed intrastate at a rate at least twice the FPC set price, will not move into interstate commerce. This is a fact of life. The interstate pipelines have become increasingly unable to pick up onshore gas.

[17] See the *Ship Shoal decision, Continental Oil Co.* v. *F.P.C.*, 370 F.2d 57 (CA 5, 1966), cert. denied 488 U.S. 910 (1967).

ESTIMATED NEW LONG-TERM CONTRACT SALES BY LARGE PRODUCERS, 1970-73, OFFSHORE FEDERAL DOMAIN VERSUS ALL AREAS

[Billion cubic feet] [1]

Year	All area [2] sales	Sales offshore [3]	Offshore percent [3]	Sales onshore	Onshore percent
1970	302.6	73.3	24.2	229.3	75.8
1971	453.7	207.7	45.8	246.0	54.2
1972	474.3	279.4	58.9	194.9	41.1
1973	330.3	221.1	66.9	109.2	33.1

[1] Figures derived from applications filed with the Commission for new long-term sales certificates.
[2] FPC pricing areas and California (Federal domain).
[3] Federal domain areas offshore Louisiana, Texas, and California.

This increased dependence of the pipelines on offshore purchases, or, to put it another way, the inability of the interstate pipelines to buy gas onshore, is attributable solely to the FPC rate structure which makes it impossible for the interstate pipelines to compete for new supplies.

As an adjunct to the problem of the interstate market becoming increasingly dependent on the offshore areas, it is critical to remember that several of our major pipelines (and therefore millions of consumers) have no means of access to the offshore area. These "land-locked" pipelines (such as El Paso, Transwestern, Nothern, Ark-La, Cities Service and MRT, simply have no ready means of attaching offshore gas. They are virtually dependent on onshore gas.

While we continue to ignore the plight of the "land-locked" pipelines, and try to pretend that the interstate consumer can achieve reliable and adequate service through development of offshore reserves alone, it is manifest that likelihood of this occurrence is less, day by day. I also conclude because of the following: [18]

	Total U.S. gas exploratory footage (million feet)	Offshore gas exploratory footage (million feet)	Offshore as percentage of total
1970	3.7	0.26	7.0
1971	3.3	.41	12.4
1972	4.6	.14	3.0
1973	6.2	.17	2.7
1974 (1st half)	3.8	.08	2.1

Less and less of the total U.S. gas exploratory effort is being directed offshore.

At the same time, the offshore development effort is slackening:

	Total U.S. gas development footage (million feet)	Offshore gas development footage	Offshore as percentage of total
1970	19.2	1.6	8.3
1971	19.3	1.7	8.8
1972	22.2	1.5	6.8
1973	29.4	2.3	7.8
1974 (1st half)	16.0	.97	6.1

[18] All figures taken from latest publication of "Gas Supply Indicators" by the FPC Office of Economics, issued October 25, 1974.

These patterns are, I believe, directly attributable to the Commission's prescription of jurisdictional rates at levels far below those of the free market. The producing segment is demonstrating that investment decisions—as to where to drill—are responsive to price and profit considerations.

Thus, rate orders like Opinion No. 669 and No. 669-H do a double disservice to the interstate consumer—the rate precludes attachment of onshore supplies, and contemporaneously causes a decline in badly needed offshore exploration and development.

The loser through all this is, has been, and will continue to be, the interstate consumer. The Commission is, simply through the process of determining rates on the basis of historic average cost, simutaneously forestalling the procurement of new supplies already found, and precluding drilling for the future supplies which might solve the shortage.

VI

Changing times and changing circumstances have cast too heavy a burden on cost-based wellhead ratemaking for it to survive.

From *Phillips*,[19] taken in conjunction with the *Ship Shoal*[20] decision, it follows that the rate at which a producer in the Federal domain offshore sells gas is controlled by the FPC, if the sale is a "sale for resale." It also follows from *Phillips* that the rate at which a gas producer onshore sells is controlled by the Commission, if he sells for resale in interstate commerce. If, however, the producer sells to the ultimate consumer, or if he sells in intrastate commerce, his sales rate is not subject to regulation by the Commission.

It is critical to note that the Courts' construction of FPC jurisdiction does not extend FPC control of production activities or facilities as such; FPC jurisdiction attaches when an interstate sale for resale, or interstate transportation, commences. This means, most simply, that the Commission cannot compel a producer to explore, nor to develop, nor to deliver uncommitted gas to the interstate market. See *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968). In *F.P.C.* v. *Transcontinental Gas Pipeline Corp.*, 365 U.S. 1 (1961) the Supreme Court put it this way: "...it must be realized that the Commission's powers under § 7 (of the Natural Gas Act) are, by definition, limited. (Citation omitted.) The Commission cannot order a natural gas company to sell gas to users that it favors: (Footnore omitted) it can only exercise a veto power over proposed (interstate transactions) . . . " 365 U.S. at 17.

Thus, it is through rate structure alone that the Commission must attempt to fulfill its statutory mandate with respect to maintenance of reliable and adequate supplies of natural gas. The Commission's rate must act as an incentive to the producer—to induce an affirmative investment decision to drill, in the first instance, and to induce the economic decision later to sell to the interstate market as opposed to the decision to hold for his own use or to sell in the intrastate market. See *Permian Basin Area Rate Cases, supra; Austral Oil* v. *F.P.C.*, 428 F2d 407 (1970), cert. denied, 400 U.S. 950; *Placid Oil Co.* v. F.P.C., 483 F2d 880 (1973).

It has not been possible for the FPC to devise a rate structure capable of fulfilling all these functions and still adhere to cost-of-service ratemaking principles. Where it possible, we would not have the shortage which now threatens the national economy. For example, if, as was true in the 1960's, the rate set is at a level where the prudent operator finds it more advantageous to turn to alternate investment opportunities, wells will not be drilled. And, if, as has been true since 1969, the rate set is at a level where the prudent operator can realize a greater return by converting his product into petrochemicals or fertilizer, he will withdraw his gas from the energy market and devote it to other uses; or, as has also been true since 1970–1971, if the FPC rate is below that offered by intrastate purchasers, the prudent operator will sell to the intrastate market.

Rate decisions of this Commission have not, of course, been set to achieve deliberately the undesirable result of a gas shortage of critical dimensions.

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[19] *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672 (1954).
[20] *Continental Oil Co.* v. *F.P.C.*, *supra*.

Rates have been set as indicated by *City of Detroit*—based on estimated rate base, estimated cost, and estimated rate of return. The focus was always backward—towards the average of historic costs spent in a past test year—and never forward.

Such an approach can never achieve the multiple demands made on the FPC rate structure. Cost-based rates cannot call forth a gas well drilling investment when an oil well drilling investment is more promising. Cost-based rates cannot command interstate dedications when intrastate dedications are more attractive.

And so, we come to the crossroads again. Is the Commission to use rate elicit drilling and dedication of new supplies to the interstate market? Or is the Commission to set rates based on costs alone? *Both objectives cannot be achieved.*

A majority of the present Commission has opted for continuation of cost-based ratemaking though they know as well as Ithat a rate so made cannot bring sufficient gas to the interstate market to alleviate the shortage.

We have reached the point in our nation's history's that the fallacy of *Permian I* ratemaking, even as modified by Opinion No. 699–H can no longer be countenanced. We have a structure which has not worked, and which cannot work.

The consumer deserves better. If this Commission will not correct that which is destroying the interstate market, then surely a reviewing court must.

VII

Producer ratemaking, as practiced by the Commission since *Permian I*, is a snare and a delusion. It has the appearance, and the stated purpose, of guarding consumers against the extortion of excessive profits by gas producers. But it has the inevitable effect of sealing off from exploration and development all but the most profitable drilling opportunities.

What occurs after an FPC rate, based on average costs, is announced? Common sense tells me that gas producers begin to measure their drilling prospects in terms of profitability. If a particular drilling prospect will be profitable at the FPC-set rate level, it will be drilled; if the economics of the venture indicate that profitability is not reasonably to be expected, the prospect is not drilled. I do not believe that any reasonably prudent operator will drill when his own best estimates of costs, and productivity, tell him that if he finds gas he can sell it only at a loss. Thus, an FPC rate is, in practical effect, a ceiling on what gas wells are drilled—but it is not a ceiling on profits.

For the long run, average cost based ratemaking guarantees a decline in exploration. Once the rate is announced, drilling operations tend to limit themselves to the average and below average cost prospect. Ironically, this process tends to maximize the profits on the fewer and fewer prospects drilled, while at the same time limiting the exploration and development of high risk, high cost prospects.

In a time of apparent plenty, this process raised few eyebrows. But now, when the need for additional supplies has become imparative, ratemaking process which penalizes frontier exploration—in deeper waters, at greater depths, in difficult territory—becomes a national affront.

I readily admit that the present situation is one most readily remedied—and most properly remedied—by Congressional action to amend the Natural Gas Act to decontrol wellhead prices. But until Congress grasps the nettle, we must all live with the Act as written. So long as producer rates are our responsibility and our duty, let us at least do our best to make the system work. It has not worked, and it cannot work, within the framework erected by the Commission in 1965 and retained by my colleagues.

It does no good whatsoever for a long dissenter to say what he would do if change were within power. The first step is for a reviewing court to recognize the inherent folly of the present structure; by the Commission. I am wholly unpersuaded that the mind of man cannot devise a more effective, more reasonable, and more just method of regulating producer rates than perpetuated by today's opinion.

RUSH MOODY, JR., COMMISSIONER.

Appendix A

Parties Filing Petitions For Rehearing

PRODUCERS

Amoco Production Company
Atlantic Richfield Company
Austral Oil Company Incorporated
Belco Petroleum Corporation
Edwin L. Cox
GHK Company and Gasanadarko, Ltd.
Mobil Oil Company
Murphy Oil Company, *et al*
The Rodman Corporation
Superior Oil Company
Tenneco Oil Company
Texasgulf, Inc.
Indicated Producer Respondents (Shell Oil Company, *et al.*) Independent Oil & Gas Association of West Virginia
Ohio Oil And Gas Association

PIPELINES

Carolina Pipeline Company
Columbia Gas System Companies
El Paso Natural Gas Company
Natural Gas Pipeline Company of America
Northern Natural Gas Company
Panhandle Eastern Pipeline Company Company and Trunkline Gas Company
Texas Eastern Transmission Corporation and Transwestern Pipeline Company
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Company
United Gas Pipeline Company
Interstate Natural Gas Association of America

DISTRIBUTORS

American Public Gas Association
Associated Gas Distributors
United Distribution Companies
Equitable Gas Company
Piedmont Natural Gas Company
Southern California Gas Company

GOVERMENTAL AGENCIES

State Corporation Commission of the State of Kansas
Oil Conservation Commission of the State of New Mexico
Public Service Commission of the State of New York
Oil and Gas Conservation Commission of the State of West Virginia
Senator James G. Abourezk

MISCELLANEOUS

General Motors Corporation

Appendix B

Parties Participating In Oral Arguments

Indicated Producer Respondents, Shell Oil Company, *et al.*
GHK Company and Gasanadarko, Ltd.
Mobil Oil Corporation
The Rodman Corporation *et al.*
Independent Oil & Gas Association of West Virginia
Kentucky Oil & Gas Association
Ohio Oil & Gas Association
Independent Petroleum Association of America
Interstate Natural Gas Association of America, *et al.*
Columbia Gas System
Consolidated Natural Gas System

El Paso Natural Gas Company
Northern Natural Gas Company
United Gas Pipeline Company
American Public Gas Association
Associated Gas Distributors
Brooklyn Union Gas Company
Equitable Gas Company
Southern California Gas Company, *et al.*
United Distribution Companies
Oil & Gas Conservation Commission of the State of West Virginia
Public Service Commission of the State of New York
Senator James G. Abourezk
Environmental Control Corporation
General Motors

Appendix C

ESTIMATED NATIONWIDE COST OF FINDING AND PRODUCING NONASSOCIATED NATURAL GAS

[Cents per thousand cubic feet at 14.73/in²a]

Cost component	1972 data	Trended data
Successful wells	5.68	6.15
Recompletions and deeper drilling	.20	.20
Lease acquisition	3.83	4.28
Other production facilities	1.28	1.39
Subtotal	10.99	12.02
Dry holes	3.77	3.72
Other exploration	2.62	2.80
Exploration overhead	.82	.82
Subtotal	7.21	7.34
Operating expenses	3.10	3.10
Regulatory expense	.20	.20
Net Liquid credit	(3.89)	(3.89)
Return on working capital	1.14	1.25
Return on investment	21.42	23.21
Subtotal	40.17	43.23
Royalty (16 percent)	7.65	8.23
Total	47.82	51.46

Derivation of Cost Components

The cost components on Sheet 1* are derived as follows:

(a) The components under the Column entitled "1972 Data" with the exception of the Return on Investment and the Royalty components are taken from Column (f), Sheet 1 of 9, Schedule No. 1, Appendix C, Opinion No. 699.* The Royalty and Return on Investment Components are computed on pages 87 and 88 of this Appendix C.

(b) The cost components under the Column entitled "Trended Data" are derived from the following base data:

	Per foot
Successful well drilling cost	$29.83
Dry hole drilling cost	$16.69
Productivity (thousand cubic feet)	485

Allocation Ratios are based upon Joint Association Survey data for 1968 through 1972.

Ratio of Lease Acquisition Costs to Successful Well Costs (1968–1972): 5739÷8327=0.6957.

Ratio of Other Exploratory Costs to Lease Acquisition Costs (1968–1972): 3792÷5793=0.6546.

Ratio of Exploratory Overhead to Dry Hole and Other Exploratory Costs (1968–1972): 1048÷8249=0.1270.

*See original transcript.

Individual Cost Components for the Trended Data are computed as follows:

Cost component		
Successful wells	6.15	=29.83÷485
Recompletions and deeper drilling	.20	(Opinion No. 662)
Lease acquisition	4.28	=6.15×0.6957
Other production facilities	1.39	=6.15×0.226
Subtotal	12.02	
Dry holes	3.72	=16.69×1.08÷485
Other exploration	2.80	=4.28×0.6546
Exploration overhead	.82	=(3.72+2.80)×0.127
Subtotal	7.34	
Operating expense	3.10	(Opinion No. 662)
Regulatory expense	.20	(Opinion No. 662)
Net liquid credit	(3.89)	(Opinion No. 598)
Return on working capital	1.25	=((7.34×1.336+ 3.10×1.689)×0.125 +4.28×1.5)×0.15
Return on investment	23.21	(Sheets 6–7)
Subtotal	43.23	
Royalty	8.23	=43.23÷(1–0.16)
Total	51.46	

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY—PART 1: COMPUTATIONS FOR 1972 DATA

Component	Year	Value	Tax credit	Net investment	Present value (time=0.5)
Other exploration	−3	2.62	1.194	1.426	2.169
Exploration overhead	−3	.82	.3739	.446	.678
Lease acquisition	−2	3.83	(1)	3.83	5.065
Dry holes	−1	3.77	1.8069	1.9604	2.254
Successful well and recompletions	−1	5.88	1.9757	3.9043	4.490
Other production facilities	−1	1.28	0	1.28	1.472
Lease acquisition tax credit	−1		1.3788	−1.3788	−1.586
Total		18.20	6.372		14.543

[1] The lease acquisition tax credit is taken in year −1.

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY—PART [1]: COMPUTATIONS FOR 1972 DATA

Computation of net cash flow:

Price	X
Royalty	−0.16X
Operating expense	−3.10
Interest on working capital	−1.14
Regulatory expense	−0.20
Tax liability to offset tax credit	−6.732
Net liquid credit	+3.89
Total	0.84X−7.282

At the midpoint of the first production year the present value of the net cash flow plus the present value of the 1.0 cents per Mcf annual escalation must equal the present value of the net investment.

From Opinion No. 699 (Appendix H, Case II and Case III)

$14.543=((0.84X-7.282)\times(1/18)\times 7.047)+((0.84/18)\times 35.829965)$

$14.543=0.3289X-2.851+1.6702$

$X=47.82$

$\text{Royalty}=0.16\times 47.82=7.65$

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY—PART 2: COMPUTATIONS FOR TRENDED DATA

Component	Year	Value	Tax credit	Net investment	Present value (time=0.5)
Other exploration	−3	2.80	1.2770	1.523	2.317
Exploration overhead	−3	.83	.3739	.446	.678
Lease acquisition	−2	4.28	(1)	4.28	5.660
Dry holes	−1	3.72	1.786	1.934	2.224
Successful well and recompletions	−1	6.35	2.134	4.216	4.848
Other production facilities	−1	1.39	0	1.39	1.599
Lease acquisition tax credit	−1		1.540	−1.540	−1.771
Total		19.36	7.1109		15.555

[1] The lease acquisition tax credit is taken in year −1.

Computation of return on investment and royalty—Part 2: Computations for trended data

Computation of net cash flow:

Price	X
Royalty	−0.16X
Operating expense	−3.10
Interest on working capital	−1.25
Regulatory expense	−0.20
Tax liability to offset tax credit	−7.1109
Net liquid credit	+3.89
Total	0.84X−7.771

At the midpoint of the first production year the present value of the net cash flow plus the present value of the 1.0 cents per Mcf annual escalation must equal the present value of the net investment.

From Opinion No. 699 (Appendix H, Case II and Case III)

$$15.555=((0.84X-7.771)\times(1/18)\times 7.047)+((0.84/18)\times 35.829965)$$
$$14.543=0.3289X-3.042+1.6702$$
$$X=51.46$$
$$\text{Royalty}=0.16\times 51.46=8.23$$

FEDERAL POWER COMMISSION

[18 C.F.R. Parts 2, 154, 157]

Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr., Rush Moody, Jr., William L. Springer, and Don S. Smith.

NATIONAL RATES FOR JURISDICTIONAL SALES OF NATURAL GAS DEDICATED TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973, FOR THE PERIOD JANUARY 1, 1975, TO DECEMBER 31, 1976—DOCKET NO. RM75-14

ORDER INSTITUTING NATIONAL RATE PROCEEDING

(December 4, 1974)

Pursuant to the Administrative Procedure Act[1] and Sections 4, 5, 7, 8, 10, 14, 15, and 16 of the Natural Gas Act,[2] proceedings are hereby instituted to prescribe rules and regulations establishing just and resonable rate for jurisdictional sales of natural gas dedicated to interstate commerce on or

[1] 60 Stat. 237, 918, 993 (1946); 61 Stat. 37, 201 (1947); 62 Stat. 99 (1948); 80 Stat. 250 (1966); 5 U.S.C. § 551, *et seq.* (1970).

[2] 52 Stat. 822, 823, 824, 825, 829, 820 (1938); 56 Stat. 83, 84 (1948); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. §§ 717c, 717d, 717f, 717g, 717i, 717m, 717m, 717o (1970).

after January 1, 1973,[3] for the biennium from January 1, 1975, to and including December 31, 1976, and otherwise regulating such jurisdictional sales by natural gas producers on a nationwide basis. Such rates will be exclusive of production, severance, or similar taxes, and subject to adjustment for these taxes, Btu content, gathering, and onshore delivery by the producer. The rate shall apply to all jurisdictional sales made within the United States and the offshore domains thereto (excluding Alaska and Hawaii) except those sales certificated under the limited-term certification procedures,[4] the small producer regulations,[5] and the optional procedure,[6] or deliveries made pursuantant to the sixty-day emergency provisions.[7]

The Commission has previously established a single uniform national rate applicable to all producing areas for post-December 31, 1973, gas supplies for the 1973-74 biennium in Docket No. R–389–B (*supra* n. 3) and has pending in Docket No. R–378[8] proceeding to establish just and reasonable rates for pre-January 1, 1973, gas supplies. This proceeding will update the rates established in Docket No. R–389–B pursuant to section 2.56a(n)[9] for the 1975–76 biennum and consider such changes in the rate structure prescribed in section 2.56a[10] as may be required by the public interest.

Our authority to so prescribe just and reasonable rates has affirmed by the courts in several cases[11] and was fully discussed in Opinion Nos. 699[12] and 699–H[13] While we are of the opinion that the Commission has authority to prescribe rates pursuant to the rulemaking procedures of U.S.C. § 553(c) (1970) in this case, we realize that some persons who become participants to this case may desire to challenge our use of rulemaking and we shall permit

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[3] The classes of gas which will qualify for the rate established herein are described in section 2.56(a)(2) of the Commission's Statements of General Policy and Interpretations. 18 C.F.R. § 2.56a(a)(2). *Just And Reasonable National Rates For Sales Of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973*, Docket No. R–389–B, Opinion No. 699, F.P.C. (June 21, 1974), *amended*, Opinion No. 699–A, F.P.C. (August 2, 1974), *reh. granted* on limited issue, Opinion No. 699–B, F.P.C. (September 9, 1974), *reh. granted* in part and *denied* in part, Opinion No. 699–H, F.P.C. (December 4, 1974). The classes described in section 2.56a(a)(2) include all gas supplies produced from wells commenced during the 1975–76 biennium and all new dedications to interstate commerce during this biennium as well as all such wells commenced and dedications made during the 1973–74 biennium.

[4] 18 C.F.R. § 2.70, *Policy With Respect To Establishment Of Measures To Be Taken For The Protection Of As Reliable And Adequate Service As Present Natural Gas Supplies And Capacities Will Permit*, Order No. 431, 45 F.P.C. 570 (1971), *amended*, Order No. 431–A, 48 F.P.C. 193 (1972), *revoked* Opinion No. 699, *supra* n. 3, F.P.C. (June 21, 1974), *reinstated* and *amended*, Opinion No. 699–B, F.P.C. (September 9, 1974).

[5] *Exemption Of Small Producers From Regulation*, 45 F.P.C. 454 (1971), *as amended* 45 F.P.C. 548 (1971), *reh. denied*, 46 F.P.C. 47 (1971), *reversed*, *Texaco Inc., et al.* v. *F.P.C.*, 153 U.S. App. D.C. 195, 474 F.2d 416 (1972), *vacated*, 42 U.S.L.W. 4867 (U.S. June 10, 1974), *on remand*, *Small Producer Regulation*, Docket No. R–393, "Notice Of Proposed Rulemaking," 39 Fed. Reg. 33241 (September 9, 1974).

[6] 18 C.F.R. § 2.75; *Optional Procedure For Certificating New Producer Sales Of Natural Gas*, 48 F.P.C. 218, *amended*, 48 F.P.C. 477, *reh. denied*, 48 F.P.C. 1002 (1972), *affirmed*, *John E. Moss, et al.* v. *FPC*, Nos. 72–1837, *et al.*, D.C. Cir., August 15, 1974 (Reversed as to pregranted abandonment, section 2.75e.).

[7] 18 C.F.R. § 157.29; *Immediate Institution Of Temporary Service By Independent Producers*, Docket No. R–155, Order No. 193, 21 *Fed. Reg.* 9166 at 9167 (1956), *as amended*, *Amendment Of Sections 157.22(D) and 157.29 Of The Regulations Under The Natural Gas Act, Relating To Exemption Of Emergency Sales By Independent Producers Of Natural Gas In Interstate Commerce*, Docket No. R–404, Order No. 418, 44 F.P.C. 1574, 1576 (1970), *revoked*, Opinion No. 699, *supra* n. 3, *reinstated* and *amended*, Opinion No. 699–B, *supra*.

[8] *Nationwide Rulemaking To Establish Just And Reasonable Rates For Natural Gas Produced From Wells Commenced Before January 1, 1973*, 38 *Fed. Reg.* 14295 (1973), "Notice Issuing Staff Rate Recommendation And Prescribing Procedures," 39 *Fed. Reg.* 34304 (September 12, 1974).

[9] 18 C.F.R. § 2.56a(n), see Opinion No. 699–H at 50–54, 85, F.P.C.

[10] 18 C.F.R. § 2.56a.

[11] *American Public Gas Association, et al.* v. *FPC*, U.S. App. D.C., 498 F.2d 719 (D.C. Cir. May 23, 1974); *Mobil Oil Corp.* v. *FPC*, 157 U.S. App. D.C. 235, 483 F.2d 1238 (D.C. Cir. 1973); *Phillips Petroleum Co.* v. *FPC*, 475 F.2d 842 (10th Cir. 1973), *cert. denied*, 414 U.S. 1146 (January 14, 1974). *See also United States* v. *Florida East Coast Ry., et al.*, 410 U.S. 224 (1973); *United States* v. *Allegheny-Ludlum Steel Corp.*, 406 U.S. 742 (1972).

[12] Opinion No. 669 at 7–15, F.P.C.

[13] Opinion No. 699–H at 3–6, F.P.C.

these persons to make such protective filings as they deem necessary to protect their right to appeal the procedures set forth by the Commission.

We do not, at this time, propose a specific rate for the 1975–76 biennium or other revisions to the rules prescribed in section 2.56a. We will, instead, rely upon the responses filed in this proceeding as the basis for modifying section 2.56a. Since cost data for 1973 have not yet been published by the Joint Association Survey (JAS), all comments pertaining to cost determinations will be deferred until after such data is published. Rather than delay all comments until the 1973 JAS data are published, we will provide that issues such as rate of return, life-of-lease contracts,[14] the Appalachian-Illinois Basin area,[15] gathering allowances, capital formation required for adequate exploration and development efforts, and other factors which may affect the establishment of a just and reasonable rate may be made the subject of written comments to be filed with the Commission on or before November 15, 1974, and responses thereto which shall be filed on or before December 13, 1974.

In addition to any other matters which participants may desire to direct their comments to, we believe that it is appropriate for such participants to present such information as they may possess on the issue of whether an increased allowance for deeper drilling and deeper water depths should be incorporated in the national rate structure and the magnitude of such an allowance (in cents per Mcf). These comments should specifically address the following items:

(i) The additional unit costs, if any, which may be associated with deeper drilling and deeper water depths as such terms are described in 18 C.F.R. § 2.56a(g)(2);

(ii) The risk associated with deeper drilling efforts and deeper water depths;

(iii) Any increment to the return allowance provided for the generally applicable national rate which might be appropriate for drilling efforts directed to depths below 15,000 feet and/or in water depths greater than 250 feet.

Specific responses to these questions will aid the Commission's determination of whether an additional allowance should be provided for such deeper drilling efforts and the possible magnitude of such an allowance. As we noted in Opinion No. 699–H, F.P.C., it is more appropriate to consider the deeper drilling issue in this proceeding rather than in a separate proceeding.

In order to assure the effective and expeditious resolution of these proceedings, all natural gas producers,[16] whether or not affiliated with an interstate pipeline company, with annual jurisdictional sales in excess of ten million Mcf,[17] and all interstate pipeline companies will be made respondents to this proceeding. A list of such persons is attached as Appendix A to this order.

Any interested person, including those persons named as respondents, desiring to participate in this proceeding shall file with the Secretary of the Commission on or before December 20, 1974, a notice of intention to participate. Those parties who have common interest shall combine in a group, where practicable and desirable. The Secretary, on or before December 31, 1974, will prepare, publish, and serve upon all persons who filed a notice of intention to participate a list of all participants including groups of participants.

We believe at the present time that there will be no need to hold a public conference or a trial-type adjudicatory hearing with oral cross-examination in this proceeding. It appears that the opportunity to file written comments and responses to the initial comments fully protect the rights of the participants to this proceeding.

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[14] See Opinion No. 699–H at 44, F.P.C.

[15] Opinion No. 699–H at 65–66, F.P.C.

[16] The term "natural gas producer" is used to refer to all persons producing natural gas including pipeline companies having exploration and production departments. An "affiliated producer" is a natural gas producer that is affiliated with an interstate pipeline company. An "independent producer" is a natural gas producer "who is engaged in the production or gathering of natural gas in interstate commerce for resale, but who is not engaged in the transportation of natural gas (other than gathering) by pipeline in interstate commerce." 18 C.F.R. § 154.91(a).

[17] Independent producers having annual sales of less than ten million Mcf are treated as "small producers." *See* 18 C.F.R. § 157.40(a)(1) and n. 5 *supra*.

The Commission orders:

(A) Proceedings are hereby instituted, pursuant to Sections 4, 5, 7, 8, 10, 15, and 16 of the Natural Gas Act of 1938, as amended, to prescribe rules and regulations establishing just and reasonable rates for jurisdictional sales of natural gas dedicated to interstate commerce on or after January 1, 1973, for the biennium from January 1, 1975, to and including December 31, 1976, and otherwise regulating such jurisdictional sales on a nationwide basis. Such rate or rates shall be exclusive of all State or Federal production, severance, or similar taxes, and shall be subjected to adjustment for Btu content, gathering, taxes, and onshore delivery by the producer.

(B) The proceeding instituted by Ordering Paragraph (A), *supra*, shall encompass an investigation of the facts, conditions, practices, and any other relevant matters pertaining to the sale of natural gas in interstate commerce. Included within such investigation shall be a determination of the cost of finding and producing new supplies of natural gas for sale in interstate commerce for resale.

(C) All persons named in Appendix A hereto are hereby made respondents to this proceeding.

(D) All persons, including the persons named in Appendix A and the Commission Staff, desiring to participate in this proceeding shall file with the Secretary of the Commission on or before December 20, 1974, a notice of intent to participate in this proceeding setting forth the name of the person desiring to participate in the proceeding and the name, title, mailing address, and telephone number of the person or persons to whom communications concerning this proceeding should be addressed; and such notices shall be submitted on letter size paper (8" by 10½" or 8½" by 11") and single spaced. The Secretary will prepare, publish, and serve upon all persons who filed a notice of intention to participate, on or before December 31, 1974, a list of all persons filing a notice of intention to participate including groups of participants.

(E) Responses in writing concerning this rulemaking proceeding shall be filed with the Secretary of the Federal Power Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 17, 1975, with respect to all matters set forth in Ordering Paragraph (B), *supra*, except the determination of the cost of finding and producing new supplies of natural gas. Replies to this submittals shall be filed with the Commission on or before February 14, 1975. All such written comments shall state the name, title, mailing address, and telephone number of the person or persons to whom communications concerning this rulemaking proceeding should be addressed. The written submittals shall be single spaced and submitted upon letter size paper (8" by 10½" or 8½" by 11"). An original and fourteen (14) conformed copies of each such response shall be filed with the Commission, and copies of all written submittals will be placed in the Commission's public files and will be available for inspection in the Commission's Office of Public Information at 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. All statements and submittals in response to this notice shall be under oath, acknowledged by a notory public or comparable official, as follows: (name) being duly sworn, deposes and says that he is (title and organization, if filing is a representative capacity) that he is authorized to verify and file this document, that he has examined the statements contained in the submittal or response, and that all such statements are true and correct to the best of his knowledge, information, and belief.

(F) Dates for the filing of written comments and responses thereto with respect to the cost of finding and producing new supplies of natural gas for sale in interstate commerce for resale shall be established by further order of the Commission upon the issuance by the Joint Association Survey (JAS) of its annual review of the United States oil and gas producing industry for the year 1973.

(G) Upon consideration of all written comments and responses to be filed in this rulemaking proceeding by the participants to the proceeding, the Commission will prescribe such amendments or modifications to Section 2.56a of its Statements of General Policy and Interpretations, 18 C.F.R. § 2.56a, as it may find to be in the public interest.

(H) The Secretary of the Commission shall cause prompt publication of this order and the accompanying Appendix A in the Federal Register and shall serve this order and accompanying Appendix A upon all persons named in Appendix A, all State Commissions, all other Federal agencies and departments, and upon all parties of record in Docket No. R–389–B.

By the Commission.

MARY B. KIDD, *Acting Secretary.*

APPENDIX A. NATURAL GAS PRODUCERS

INDEPENDENT PRODUCERS

Amerada Hess Corporation
American Petrofina Co. of Texas
Amoco Production Company
Ashland Oil, Inc.
The Atlantic Richfield Company
Austral Oil Co., Inc.
Aztec Oil and Gas Company
Bass Enterprises Production Company
Perry R. Bass
Belco Petroleum Corporation
Beta Development Company
Cabot Corporation
California Company, a Division of Cheron Oil Company
Champlin Petroleum Company
Chevron Oil Co., Western Division
Clinton Oil Company
Coastal States Gas Producing Company
Coltexo Corporation
Continental Oil Company
Cox, Edwin L.
Diamond Shamrock Corporation
Dorchester Gas Production Company
Exchange Oil and Gas Company
Exxon Corporation
Felmont Oil Corporation
Forest Oil Corporation
General American Oil Co. of Texas
Getty Oil Company
Gulf Oil Company
Helmerich & Payne, Inc.
J. M. Huber Corporation
Hassie Hunt Trust
Hunt Oil Company
Imperial American Management Company
The Jupiter Corporation
Kerr-McGee Corporation
King Resources Company
LVO Corporation
Louisiana Land and Exploration Company
McCulloch Gas Processing Corporation
McCulloch Oil Corporation
McCulloch Oil Corporation of California
McCulloch Oil Corporation of Texas
MAPCO Inc.
Marathon Oil Company
George Mitchell and Associates
Mobil Oil Corporation
Monsanto Company
Murphy Oil Corporation
Natural Gas & Oil Company
NorthEast Blanco Development Corp.
Ocean Drilling & Exploration Company

Oklahoma Natural Gas Gathering Corporation
Petroleum Inc.
Phillips Petroleum Company
Pioneer Production Corporation
Placid Oil Company
Pubco Petroleum Corp.
River Corporation
The Rodman Corporation
Shell Oil and Gas Company
Signal Oil and Gas Company
Skelly Oil Company
Sohio Petroleum Company
The South Coast Corporation
Southern Union Gathering Company
Southern Union Production Company
Stephens Production Company
Sun Oil Company
Suburban Propane Gas Company
Superior Oil Company
Tennessee Gas Company
Terra Resources, Inc.
Texaco Inc.
Texas Oil and Gas Corporation
Texas Pacific Oil Company, Inc.
Transocean Oil, Inc.
Union Oil Company of California
Union Texas Petroleum, Division of Allied Chemical
Warren Petroleum Corporation, A Division of Gulf Oil Corp.

AFFILIATED PRODUCERS

Anadarko Production Company
CIG Exploration, Inc.
Cities Service Oil Company
Colorado Oil and Gas Company
Columbia Fuel Corporation
Columbia Gas Development Company
El Paso Products Company
La Gloria Oil and Gas Company
Lone Star Gathering Company
Lone Star Producing Company
NAPECO Inc.
Nothern Natural Gas Producing Company
Northwest Production Corporation
Odessa Natural Gasoline Company
Pan Eastern Exploration Company
Pennzoil Company
Pennzoil Producing Company
Pennzoil Offshore Gas Operators
Pennzoil Louisiana and Texas Offshore
The Preston Oil Company
Southern Natural Gas Company Joint Venture
Tenneco Oil Company
Texas Gas Exploration Corporation
Texoma Production Company

PIPELINE PRODUCERS

Arkansas Louisiana Gas Company
Arkansas Oklahoma Gas Corporation
Carnegie Natural Gas Company
Colorado Interstate Gas Corporation
Consolidated Gas Supply Corporation
El Paso Natural Gas Company
Equitable Gas Company
Inland Gas Company, Inc., The Iroquois Gas Corporation

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Kentucky West Virginia Gas Company
Lake Shore Pipe Line Company
Michigan Wisconsin Pipe Line Company
Mid Louisiana Gas Company
Mississippi River Transmission Corporation
Montana-Dakota Utilities Company
Mountain Fuel Supply Company
Natural Gas Pipeline Company of America
North Penn. Gas Company
Northern Natural Gas Company
Northern Utilities, Inc.
Panhandle Eastern Pipe Line Company
Pennsylvania Gas Company
Southern Natural Gas Corporation
Sylvania Corporation
Tenneco Inc.
Texas Eastern Transmission Corp.
Texas Gas Transmission Corporation
Trunkline Gas Company
United Natural Gas Company
Western Gas Interstate

PIPELINE RESPONDENTS

Alabama-Tennessee Natural Gas Company
Algonquin Gas Transmission Company
Arkansas Louisiana Gas Company
Arkansas-Missouri Power Company
Arkansas Oklahoma Gas Corporation.
Black Marlin Pipeline Company
Blue Dolphin Pipe Line Company
Bluebonnet Gas Corporation
Bluefield Gas Company
Caprock Pipeline Company
Carnegie Natural Gas Company
Cascade Natural Gas Company
C. B. Gas Gathering Inc.
Chandeleur Pipe Line Company
Cimarron Transmission Company
Cities Service Gas Company
Colorado Interstate Gas Co., A Division of Colorado Interstate Corporation
Columbia Gas Transmission Corporation
Columbia Gulf Transmission Company
Commercial Pipeline Company, Inc.
Consolidated Gas Supply Corporation
Consolidated System LNG Co.
Delta Gas, Inc.
East Tennessee Natural Gas Company
Eastern Shore Natural Gas Company
El Paso Natural Gas Company
Equitable Gas Company
Farmland Industries Inc.
Florida Gas Transmission Company
Gas Transport, Inc.
Grand Gas Corporation
Grand Valley Transmission Company
Granite State Gas Transmission, Inc.
Great Lakes Gas Transmission Company
Gulf Energy and Development Company
Hampshire Gas Company
Horner and Smith
Industrial Gas Corporation
Inland Gas Company, Inc.
Inter-City Minnesota Pipeline Ltd., Inc.
Iroquois Gas Corporation
Kansas-Nebraska Natural Gas Company
Kentucky-West Virginia Gas Company

Lake Shore Pipeline Co.
Lawrenceburg Gas Transmission Corporation
Lone Star Gas Co.
Louisiana-Nevada Transit Company
McCulloch Interstate Gas Corporation
Marengo Corporation
Michigan Gas Storage Company
Michigan Wisconsin Pipe Line Company
Mid Louisiana Gas Company
Midwestern Gas Transmission Company
Mississippi River Transmission Corporation
Montana-Dakota Utilities Company
Mountain Fuel Supply Company
Mountain Gas Co.
National Fuel Gas Supply Corporation
Natural Gas Pipeline Company of America
North Penn Gas Company
Northern Natural Gas Company
Northern States Power Company (Wisconsin)
Northern Utilities, Inc. (Wyoming)
Northwest Pipeline Corporation
Ohio River Pipeline Corporation
Oklahoma Natural Gas Gathering Corporation
Orange and Rockland Utilities, Inc.
Pacific Gas Transmission Company
Panhandle Eastern Pipe Line Company
Penn-Jersey Pipe Line Company
Pennsylvania Gas Company
Plaquemines Oil and Gas Company
Raton Natural Gas Company
Regis Gas System Inc.
Sabine Pipe Line Company
Sea Robin Pipeline Company
South County Gas Company
South Georgia Natural Gas Company
South Texas Natural Gas Gathering Company
Southern Energy Co.
Southern Natural Gas Company
Southwest Gas Corporation
Standard Pacific Gas Lines, Inc.
Stingray Pipeline Company
Sylvania Corporation
Tennessee Gas Pipeline Company, A Division of Tenneco, Inc.
Tennessee Gas Pipe Line Company
Tennessee Natural Gas Lines, Inc.
Texas Eastern Transmission Corporation
Texas Gas Pipe Line Corporation
Texas Gas Transmission Corporation
Tidal Transmission Company
Transcontinental Gas Pipe Line Corporation
Transwestern Pipeline Company
Trunkline Gas Company
Union Light, Heat and Power Company
United Gas Pipe Line Company
United Natural Gas Company
Urban Pipe Line Company
Valley Gas Transmission, Inc.
Washington Natural Gas Company
West Texas Gathering Company
Western Gas Interstate Company
Western Transmission Corporation
Zenith Natural Gas Company

Representative MOORHEAD. The Committee would now like to hear from Gordon Corey, Frederick Mackie, and Murray L. Weidenbaum. I would like to suggest that all three of you come forward at this time, and we will hear from all the witnesses before we ask questions. I would like to yield to Senator Proxmire if he wants to make a statement. I understand you do have a quorum call?

Senator PROXMIRE. Yes; I would like to apologize to Mr. Mackie. I wish very much I could be here and hear his testimony. I know it is excellent and I will certainly read it carefully, but unfortunately there is a live quorum in the Senate. They are about to vote on a cloture motion. I haven's missed a vote in 8 years, so I must leave although I would like to stay and hear your testimony, I will also read the testimony of Mr. Corey. I really am grateful to Professor Weidenbaum for his appearance.

Representative MOORHEAD. We will proceed with Mr. Corey. If you summarize your excellent statement, the entire statement, together with the various attachments and appendices, will be made a part of the record, without objection.

STATEMENT OF GORDON R. COREY, VICE CHAIRMAN, COMMONWEALTH EDISON CO.

Mr. COREY. Thank you very much. I will try to make my summary very brief, because I am sure discussion is more important than anything else.

One of the basis I suppose for my appearing here this morning is that Chairman Nassikas and the other members of the Federal Power Commission appointed me as Chairman of the Technical Advisory Committee on Finance to advise the Federal Power Commission on financial problems facing the electric utility industry. This appointment was made about 2 or 3 years ago, and our Committee is almost ready to turn in its report. I have attached and enclosed with my prepared statement a number of exhibits which represent excerpts from the latest draft of our Committee's report. I want to emphasize that the conclusions set forth in this draft have not been approved by all members of the Committee, not formally approved. I believe we do have tacit approval. We have been working on this a long while. It is a broad-gaged committee, involving men from Harvard, from Wall Street, from the investment community, from the electric power industry, from the investor-owned utilities, from the American Public Power Association, from the city of Seattle, from municipal utilities, from the REA's, and from a number of U.S. Government agencies, like EPA, AEC, the Department of the Interior, and CEQ.

The overall conclusions could be, I think, summarized very briefly, I mean, the conclusions of our Committee's report, and these are: First, that the electric power industry is by far the most capital intensive of any industry. This is set forth clearly on the first page of exhibit D, which shows that the electric power investment per dollar of annual sales was, at the end of last year, $4.25, which is, for example, six times that of the oil industry, and seven times that of the automobile industry, and four times that of the steel industry. These are industries which are normally thought of as being capital intensive, but the electric power industry has a tremendous need for capital. Our projections are that we will be spending approximately $650 billion on new construction during the next 15 years, and that we will be raising roughly $400 billion in external financing during the next 15 years, and that is $27 billion on the average for a year, and during the next 5 years alone, we will be raising $15 billion in average annual external financing. That compares with a current level of financing of about $10 billion.

Mr. Nassikas said a short time ago that it is very difficult to market new issues of common stock today, and you can say that again. The stock market has been on its back. It is getting a little better, but the electric power industry must raise $3 billion of common equity money per year during just the next 5 years. We've got to sell $15 billion of common stock in the next 5 years.

Commonwealth Edison alone is scheduled to raise as much new common stock—I mean, to sell as much new common stock in the next 5 years as it already has outstanding. This, in a nutshell, is the problem of the electric power industry, and to a large extent, I think it is a problem of the United States as a whole, namely, not so much a shortage of Btu's, a shortage of energy, but a shortage of capital. We do have some recommendations. The recommendations are summarized very briefly in exhibit A, which is attached to my testimony, It is a single sheet.

In essence, exhibit A, beginning about the middle of the page, says that one of the things that must be done is that electric management, electric utility management, must be better than ever, be diligent, must be efficient, and must run a tight ship.

Second, electricity rates must be high enough to recover costs, and unfortunately, rate increases have not been keeping up with cost increases, and the industry has suffered, as witness some serious problems with companies such as Consolidated Edison of New York. And I think the worst thing that has happened, however, and this is partly due to a reduction in estimates of future load requirements, but it is inevitably importantly due to difficulties in financing, is that more and more utilities have been cutting back on their construction programs. That was pointed out in my prepared remarks, and the cutbacks to date for the next 5 years amount to approximately $16 billion and this represents something on the order of 150,000 to 200,000 jobs in the construction industry. This is a very serious matter and it probably isn't going to get better immediately.

The public must be made aware of the critical need for adequate rates. I am summarizing what this report, which is my exhibit A, says. Also, rate structures must be modified to trim peakloads. In this respect, I am in complete agreement with you, Mr. Moorhead. We do need peak and offpeak pricing. I will respond to that in just a moment, but continuing, regulatory processes need to be streamlined and speeded up. Turning to the last item on here, Mr. Moorhead, so far as the publicly owned systems are concerned, it is important that we recognize that the municipal systems and the public utility districts and other publicly owned systems throughout the United States have serious fund raising problems, as well. It is important that the tax exempt features of financing, which are available to them, not be eroded away. I am reflecting what my colleagues in the public side of the business have said many times, that they are having difficulties, and they have difficulties with municipal budgets, and difficulties with city councils to approve the additions that need to be made. It is important, I think, that we pay attention to their problems as well as to those of the investor-owned industry.

Now, specifically, our report has some recommendations for the U.S. Government; recommendations with respect to taxes. Indeed, one of your questions had to do with the 4-percent investment tax credit and the 7-percent investment tax credit, and the 10-percent investment credit, and so forth. Basically, we feel that the electric power industry should be treated like any other industry, and that we should at least be granted the 7-percent investment credit which is available to other industries. This is merely a rather small way of mitigating to a small degree the perverse effect of the corporate Federal income tax upon capital formation and plant modernization. It is not a major matter which will solve the industry's problems. I brought that out in my prepared testimony, Mr. Chairman. So far as Commonwealth Edison is concerned, we have to raise $400 million in new financing between now and next June 30. The investment tax credit will give us about $15 million on a 4-percent basis, or something like that. It is important, but it is not going to solve the $400 million fundraising problem.

We do have a recommendation which would go a long way toward helping stimulate capital formation in this country and we are becoming short of capital and we do have policies which discourage capital formation. The recommendation is to allow the electric power industry—and incidentally, which traditionally and by the very character of its stockholders, you know, there are a lot of small stockholders basically who must live on their dividends, and by the very character of its nature, it can't make a sharp cut in dividend payments—if it would be possible—and incidentally, Consolidated Edison tried it, and the whole utility market went down, and Potomac Electric Power tried it a couple of years ago, with disastrous effects on the market value of the stock. But companies in the industrial field, generally, are able to finance their capital needs by plowing back earnings into the business tax free, as far as the stockholder is concerned. For instance, IBM pays out very little in dividends, and Xerox and Polaroid pay out very little in dividends. General Motors and the steel companies, compared with the electric power industry, pay out a very small percentage of their earnings in dividends, and are able therefore to raise a good deal of their capital needs through internal cash generation and retention of earnings. The electric power industry, because of its tradition and because of the kind of stockholders it has, just can't do that. We are paying out 70 to 75 to 80 percent of earnings in dividends. What I have asked, and I talked to the Ways and Means Committee staff about this, and I talked with Treasury about this, is that permission be given through an appropriate amendment of the Internal Revenue Code to allow either the tax-free reinvestment of dividends, that is for a person who reinvests his dividends promptly under an established plan, not to be taxed for those dividends, or for a person to be allowed to elect to hold a stock which pays stock dividends instead of cash dividends. This was allowed prior to the 1969 Tax Reform Act. It is still being done by Citizen Utilities Co., which has been doing it for about 20 years, and has not had to raise any new common equity money as a result. This would solve one-third to one-half of the electric power industry's moneyraising problems if we could somehow reward individual investors; that is, the little people who own our stock. Commonwealth Edison's stock is more than half owned by small individuals and by small trust accounts with beneficiaries who need income. We recommend rewarding them for saving and putting their money back into the business. There have been numerous other sorts of proposals along the same line. I make this as a specific recommendation. it is in our draft report in exhibits A, B, and C.

Next, I make as a specific recommendation that we pay very, very close attention to the costs, to the relative costs and benefits associated with environmental requirements. I know this is a very large subject, and I will stop right there.

Finally, I did want, if I can have 1 or 2 minutes, to respond specifically to the five questions that are in the press release that was passed out at the door. The first question is: Have recent energy conservation efforts significantly reduced the need for generating capacity? I would say guardedly, yes. We have had a leveling of electricity sales growth this year. This has resulted from a number of things. In general, we have not had any growth in peakloads over last year. For the country as a whole, it could be on the order of 1 percent, but it is in that general range, and it seems to me that this leveling has been brought about by conservation, by poor business, by a very cool summer, and by some price elasticity due to substantially higher electricity prices on the east and west coasts.

However, I do have no doubt that the recent conservation efforts have had a significant effect.

The second question is, what is responsible for the slow pace with which the utility industry is adopting peakload pricing? You had a long discussion with Mr. Nassikas about this. I am personally very much in favor of peak/offpeak pricing, and I also recognize it is an extremely important and a difficult matter. I am responding to the question which you asked—and I think you were referring to time-of-day metering, or peak/offpeak pricing for small residential customers—and in responding to that question, this is a very dangerous area; that is, I don't want to rush into this thing foolishly. This is the reason there has been some footdragging in this area. We need to know more about price elasticity and demand. We at Commonwealth Edison are working with the Illinois Commerce Commission on a comprehensive electricity study. We are watching the Madison Gas & Electric study very carefully. We think that the Vermont study is not very relevant to our problem because Vermont is a winter peaking area, and not a summer peaking area. The real problem is what is going to happen on the 98-degree day or the 99-degree day in New York or Chicago in high rise buildings, where you can't open the windows. You are up there, and you just have to have the air-conditioning on. We are very much afraid that unless we know exactly what we are doing, that what we will end up with having seasonal peak/offpeak pricing that will create needle peaks, that is, that we will shut off the air-conditioning on 85 and 90 degree days, and leave it on full blast on the 100-degree day, and we will have just as much peakload as we ever had, but we won't have as much offpeak load. Now, this is something that is terribly important. This needs to be dealt with. I think that work is going ahead in several areas to develop better data, but meanwhile I think it is terribly important that we move forward with peak and offpeak pricing in the large industrial and commercial areas.

England is doing it, England has interruptible rates as well. American Electric Power has had interruptible as well as peak pricing for many years. We have had one form or another of peak/offpeak industrial pricing for as long as I have been in the company. The French have the Green Tariff, which applies incidentally to just the large customers. I think it is 12,000 volts and over. They believe, although they can't quantify their results, but I asked them at the Madison conference a month ago to do that, and they said that they never added up the co-incident loads on their Green Tariff customers, so that they couldn't tell me precisely what the effect has been, but they believe it has been significant so far as load leveling is concerned.

The third question is: Is the small consumer being discriminated against when he or she pays twice as much per unit as the large industrial customer? I can only speak for Commonwealth Edison. On every rate case we run very careful cost-of-service analyses, and we generally find that if there is any bias at all, it is in favor of the small residential customers, so my own answer on this is, "No."

Next, is the consumer being penalized for voluntary energy conservation through the imposition of higher utility rates? And I can only again answer for the Middle West, and there I would say, "No."

Finally, will the Administration's new rebatable investment tax credit to billions of dollars of direct subsidy? Will this be a bailout? I would rather not make a direct answer. I would rather that I say I favor moving the investment tax credit up to 7 percent for electric power companies. If we are going to move it up to 10 percent for everyone, we should move it to 10 percent for electric power companies. I have very mixed feelings, as you do, about the refundable features. I think that the 50-percent limitation should be taken off. I think it is unfortunate and the 50-percent limitation hurts exactly the companies that need help the most. That is not Commonwealth Edison. It is American Electric Power, and some of the east coast companies, and Detroit, consumers, and the like.

That is all, and I am sorry I took so long.

[The preapred statement of Mr. Corey, together with exhibits follow:]

PREPARED STATEMENT OF GORDON R. COREY

I am Vice Chairman of Commonwealth Edison Company which serves electricity to Chicago, the metropolitan area surrounding Chicago in Illinois and the suburban and rural areas stretching westward to the Mississippi, roughly the northern one-third of Illinois. Our electric service territory includes approximately 11,000 square miles, 390 Communities and a population of approximately eight million.

I am also chairman of a Technical Advisory Committee on Finance which about two years ago was established by Chairman John Nassikas and the other members of the Federal Power Commission to advise the Commission in connection with the preparation of the National Power Survey. Our committee has virtually completed its work of analyzing the financial problems of the electric power industry and making recommendations for the solution of these problems. There is attached to this prepared statement the following exhibits which represent the latest drafts, still subject to change and not yet formally approved by the members of the Technical Advisory Committee, of portions of our proposed report:

Exhibit A—a single page summary statement entitled, "The Report in Brief."
Exhibit B—an eight page statement entitled, "Highlights," summarizing in somewhat greater detail the contents of the report.
Exhibit C—an even longer and more detailed summary statement entitled, "Introduction and Summary."
Exhibit D—a draft of the first chapter of our report, entitled, "Financial Needs of the Electric Power Industry."
Exhibit E—a list of the members of the Technical Advisory Committee on Finance.

The drafts of the Committee's report in full are available as a matter of public record in the office of the Federal Power Commission.

Based upon my experience with Commonwealth Edison Company, and also my experience in working with the Technical Advisory Committee on Finance, over the past two years, I submit the following comments on various subjects which the Joint Economic Committee has asked me to cover in connection with its emergency inflation study.

I. Future growth of electricity generation and usage

The long-term future rate of growth in electric generating capacity requirements is under considerable discussion today. Traditionally, the electric power industry in the United States has shown year to year growth of system peak loads and electric generating requirements in the range of seven to eight per cent per year. This year, 1974, however, the peak load demand for electricity has remained about level for the U.S.A. as a whole. Our Technical Advisory Committee on Finance is estimating a one per cent growth in peak load demand this year. We at Commonwealth Edison believe that our system peak demand would have grown about one and a half per cent this year had it not been for extremely cool weather, which held our 1974 summer peak below that of 1973.

As to what the future will bring, it would be helpful to refer to Exhibit D. This chapter sets forth detailed financial projections and also indicates the input assumptions which were used in making each of such projections. We used a technique of selecting some eight different cases or scenarios. The growth assumptions for each of these eight cases are set forth in Exhibit 2 of Chapter I. For the moderate growth cases (I and IA)—those which I believe represent the more likely possibilities for the future—peak load growth in 1975 is estimated at four per cent compared with 1974. Thereafter, annual percentage growth rates are estimated at 6.5 per cent for the 1976 to 1980 period, at 6.0 per cent for the 1981 to 1985 period and at 5.5 per cent for the 1986 to 1990 period.

Based on case IA, projected future financing requirement for the electric utility industry are very great.

The electric power industry is already the most capital intensive of all, having $4.25 invested in plant and equipment for every dollar of revenue received. For the 1975–89 period following case IA, it is estimated that the electric power industry's construction expenditures will total $650 billion, that of this total $400 billion or an average of $27 billion a year must be raised externally, and that during the next 5 years alone, $15 billion per year must be raised externally compared to current external requirements of $10 billion annually. Common stock sales alone are expected to total $15 billion in the next five years.

In addition to the preferred Cases I and IA—the moderate growth projections —we made a number of other different projections representing alternative possibility which may well come to pass under certain circumstances.

Case II is based upon roughly the historic growth experience of the industry; Case III is a very low growth rate case; Case IV assumes a high "all electric" rate of future growth: Case V assumes virtually zero growth; Case VI is a "topping-out" case, and Case VII, a modified topping-out case. (The rate of growth for Case IA is the same as for Case I, the variation between the two being not in the rates of growth but in the required environmental expenditures assumed.)

I will not spend a large amount of time discussing these various cases. Suffice it to say that many different things could happen in the future which would tend to make one or another of these cases come true. For example, the current leveling off of growth in 1974 appears to have resulted from a combination of factors—conservation, the business recession, abnormally cool summer weather and a dampening in the rate of usage due to higher electricity prices particularly on the east and west coasts as a result of sharply increased costs of oil used for generation in these areas.

Whether or not the business recession will continue to deepen in 1975 and whether the effect of higher electricity prices will have an even greater dampening effect upon electricity usage in the future is hard to determine at this time. Whether or not conservation efforts, which have become somewhat moderated, will become more pronounced in 1975 is also difficult to determine. What the policies of the oil exporting countries will be—and what the price and availability of oil for electric generation will be in the next year and ensuing years is a large unknown.

Whereas it seems to me that the moderate growth cases (Cases I and IA) represented the most likely possibilities for the future, nevertheless there is a possibility, if business conditions should continue very poor, that these cases overstate the near-term growth—and contrariwise, if other forms of energy become in short supply, they may understate the long-term growth rates.

For Commonwealth Edison Company alone we are estimating rates of growth in system peak load for the next few years as follows:

	Percent		Percent
1975	3.8	1981	6.3
1976	7.7	1982	6.3
1977	7.5	1983	6.1
1978	6.7	1984	6.1
1979	6.6	1985	5.9
1980	6.5		

THE RELATIONSHIP BETWEEN SYSTEM PEAK LOADS AND TOTAL ELECTRICITY USAGE

I have been asked to comment upon the question of what might be done "to improve the rate of capacity utilization of the electric utility industry."

It is customary in our industry to refer to two measures of capacity utilization—one is the system load factor, the other is the system capacity factor.

The annual system load factor may be defined as the ratio of (i) total kilowatthour output of an electric power system for a 12 month period to (ii) the theoretical amount of output which would have occurred if the peak energy output (the output during the peak period—the highest single half-hour or hourly output period during the year) had been produced and sent out continually throughout the year.

The annual system capacity factor is similarly determined except that the denominator is the product of the total generating capacity available (rather than peak load) multiplied by the number of hours in the year, normally 8760.

For Commonwealth Edison Company, the annual system load factor in 1973 was 55%. We strive to have a system reserve of approximately 14%, last year it was 18.9%. Consequently our 1973 system capacity factor was approximately 81% of the load factor or 45%.

Our annual system load factor has declined during the last 10 years from 62% in 1963 to 55% in 1973. Our annual system capacity factor has similarly declined from 52% in 1963 to 45% in 1973.

Similar deterioration in load and capacity factors has occurred for many major U.S. systems, particularly those systems with summer air conditioning peaks.

Peak load pricing

It has been suggested that peak load pricing (using long-run incremental pricing to price peak period usage) can be used to improve the rate of capacity utilization, and thus perhaps, reduce somewhat the need for future generating capacity additions and hence the financial requirements of the industry.

These statements are undoubtedly true from the viewpoint of conventional economic theory. However, there are some serious problems with their implementation as follows:

(a) *Price elasticity.*—It is not clear how price-elastic peak period usage really it. There is some worry that the use of higher summer time rates, compared with winter time rates, would simply narrow the usage of air conditioning equipment, restricting its usage on mild days but having little effect on the hottest days of the year, thus aggravating peak conditions, creating needle peaks and reducing overall system capacity factors still more.

(b) *Peak period pricing penalties.*—It has been suggested that some form of pricing might be adopted which would shaply penalize usage on the hottest days of the year, say to charge as much as $10 or $15 for use of a window air conditioner on a single hot day. But I shudder to contemplate the problem of handling the customer complaints resulting therefrom. If we think we have problems today, consider the problem of explaining to a high-rise apartment dweller (luxury or moderate or public housing) what happened to his electric bill as a result of his necessary use of fans and ventilating equipment on a hot day.

(c) *Time-of-day metering.*—It has been suggested that we might attempt to use time-of-day metering for small residential and commercial customers, just as Electricité de France does for approximately four million of its 25 million domestic electric customers. However, there are considerable problems with time-of-day metering, for small customers. The English have just rejected it after a long study of the relative economics involved. Some people in this country feel that there were mistakes made in the English study, but it probably is as good as any made to date. There is no question that time-of-day metering is expensive. I would estimate that its implementation on the Commonwealth Edison system would require an investment on the order of $100 a meter or $250 million for our 2½ million residential and small commercial customers and the additional annual costs would amount to $62 million.

The English experiment over an extended period indicated that the game was not worth the candle—that the resulting economies did not justify the added expenditures. While the situation in England is different from that in this country—for one thing their system is winter-peaking rather than summer-peaking—nevertheless, they were concerned primarily with determining whether they could switch a substantial portion of residential usage from daytime to nighttime through differential pricing—and this would be our objective as well.

Conclusion.—It seems to me that we could and should make greater use of peak and off-peak period differential pricing for large industrial and commercial customers.

The Electricité de France people have a much publicized tariff known as the Tarif Verte—the Green Tariff—which provides for such differential pricing for large commercial and industrial customers. They feel that the Green Tariff has had a significant load leveling effect but seem unable to quantify it.

We ourselves at Commonwealth Edison Company have had considerable experience with such tariffs over the years and have recently filed additional peak-offpeak price differentials for large users.

On the other hand, I believe considerably more studies of price elasticity and the effect of differential time-period pricing in the residential and small commercial areas need to be made before we embark on large scale time-of-day metering and peak period pricing for residential and small commercial customers.

II. The high cost of electric generating capacity

During the first 15 or 20 years following the close of World War II, there was a steady decline in base load electric generating capacity construction costs. Here are some figures for Commonwealth Edison which illustrate this. During this early postwar period, Commonwealth Edison generating station construction costs declined from a high of $226 a kilowatt for Ridgeland Station generation units 1 and 2. which were completed and placed in service in 1950 and 1951, to a low of $98 per kilowatt for Joliet Station generating units 7 and 8 which were completed and placed in service in 1965 and 1966. About that time, 1965. we ordered our first large scale nuclear generating units, Dresden 2 ano 3. which were then scheduled for service in 1969 and 1970. They were actually placed in service about 18 months late, in 1970 and 1971. at a cost of $145 a kilowatt. Shortly before that, in 1967 and 1968. we placed two fossil fuel generating units in service at Kincaid at a cost of $116 a kilowatt.

Since then generating station construction costs have steadily risen. Powerton Unit 5, a coal fired unit, was completed in 1972 at a cost of $232 a kilowatt. In 1973 and 1974, Zion nuclear units 1 and 2 were completed at a cost of $281 a kilowatt. And our future base load generating station construction costs are expected to be considertbly higher. For example our Byron and Braidwood nuclear units which are scheduled for service in 1980, 1981 and 1982 have an estimated construction cost of $472 a kilowatt. Moreover our projections beyond 19881 and 1982 indicate that we may well be in the $500 and $600 per kilowatt range before the mid 1980's. On the east coast, as I am sure this committee is aware, there are base load generating units contemplated for service in the late 70's or early 80's with construction costs in the $700 to $800 range.

Exhibit F attached to this testimony is a tabulation of the estimated cost of generating units for Commonwealth Edison and subsidiary companies. These figures exclude the cost of land.

(a) Construction cost inflation

Under this general heading I would include both the effects of general inflation, as measured by the cost of living index or the GNP price deflator, and the fact that construction labor costs have escalated more rapidly than general inflation during the past 10 years.

(b) Environmental requirements

These requirements have increased the costs of equipment and facilities required at our new nuclear and fossil fueled stations by roughly $50 a kilowatt. This figure represents a rough approximation of the added cost of closed-cycle cooling facilities, facilities for limiting chemical and waste emissions to the water, and facilities for limiting emissions to the air. They include such items as larger precipitators on our coal-fired stations; cooling towers, cooling lakes and spray canals for closed-eyle cooling at both coal-fired and nuclear stations; facilities to eliminate chemical and waste run off; facilities to restrict radioactive emissions to virtually zero, and finally, of course, research and development facilities for the removal of sulfur from stack gases.

In addition to these increased capital costs, there is the much increased cost of low-sulfur fuel coal from Wyoming and Montana instead of high sulfur coal from Illinois. These costs have not entered into generating station construction cost but the switch *has* affected the capital requirements for additional freight trains to haul the coal, and it *has* significantly affected the price of electricity.

(c) Drawn-out construction schedules

It takes almost twice as long to complete a generating unit today as it used to. We used to plan, routinely, upon a 48-month construction schedule. When I signed the contracts for the purchase of Dresden Nuclear Units 2 and 3 on February 5, 1965, the contract date for commercial service of Dresden 2 was February 5, 1969 and for Dresden 3, February 5, 1970. These units were brought in about 1½ years late, Dresden 2 on August 11, 1970 and Dresden 3 October 31, 1971.

By contrast, we are now planning on construction schedules of approximately eight years. Byron 1 and 2 were ordered on Mtrch 28, 1971 and Braidwood 1 and 2 were ordered on September 24, 1972. These units are now scheduled for commercial operation in October 1980, October 1981 and October 1982 respectively. However, even before we extnded their schedules by one to one and one-half years a few months ago (and it was doubtful then whether the old schedules could be met) the schedules had an average length of approximately eight years from ordering date to service date for each of the four units. The stretch-out from 4 years to 8 years is primarily a result of the increased time needed to take care of siting and licensing difficulties. Also, requirements for upgrading and back fitting throughout the construction period must now be counted upon as almost routine—and construction delays for such work must be allowed for in the schedule.

This stretch-out in construction time, coupled with the very much higher cost of money, has increased the interest during construction and related overheads from a figure of $8 a kilowatt on Joliet 7 and 8, which were completed in 1965 and 1966, to estimates of over $80 a kilowatt for the Byron and Braidwood units. This $70 to $75 a kilowatt increase is primarily due to increased interest capitalized; i.e., the cost of money invested throughout the construction period in partially completed facilities.

WHAT CAN BE DONE ABOUT INCREASED CONSTRUCTION COSTS?

Careful consideration *must* be given to the relative costs and benefits related to each new environmental requirement. For example, a wide-ranging requirement to install stack gas scrubbers on fossil-fired stations, as has been suggested could contribute *sharply* to future generating construction cost increases.

I believe that the Atomic Energy Commission (to be followed by the newly created Nuclear Energy Regulatory Commission) is doing its best to look after the public interest, to determine that all proper licensing, safety and environmental questions are inquired into thoroughly—and I believe at the same time that they are doing their best to expedite the proceedings so as not to have unnecessary delays. However, there is no question that the various new licensing and environmental requirements, including those imposed by the Water Quality Act, the Clean Air Act, and related new siting and licensing procedures, have had a significant effect upon the overall cost of electric generating station construction.

I have been assured many, many times by friends and customers that they would be glad to pay the added cost to assure that steps are taken to avoid making siting errors and to assure that the environment will be protected. I believe that people are sincere about this—but I know that they also sometimes forget the requirements that have been imposed and now must be paid for.

III. The liberalized investment tax credit

Commonwealth Edison Company's five year construction program for 1975 to 1979 is a $4.3 billion program averaging $860 million a year, as follows: 1975, $700 million; 1976, $700 million; 1977, $800 million; 1978, $1.0 billion; and 1979, $1.1 billion.

During 1974 our gross 4% investment tax credit amounted to $11 million. During 1975 it is expected to be $17 million at the 4% rate. For the five year period, 1975 to 1979, the total investment tax credit, based upon a 4% allowance, will amount to $100 million, an average of $20 million a year. Raising the 4% to 7% would increase the five year investment tax credit by approximately $75 million or $15 million a year. This is important; it is significant; it is most necessary; but it will only supply a portion of the $4.3 billion which we must raise to finance our five year construction program.

It is important to recognize that every effort must be made to improve the internal cash generation of the electric power industry and to help the industry finance as large a portion of their construction expenditures as possible with internally generated funds. The increase in the investment tax credit is a step in the right direction. However, there are a number of companies in the industry whose financial condition is so bad that they are paying little or no income taxes and for these companies the 7% credit will not be of much help unless accompanied by such changes as raising the 50% limitation to 75%, and the refunding provisions proposed by the President.

As to the effect of President Ford's proposal for increasing the investment tax credit from 4% to 10%, the immediate effect would be somewhat larger than that which I have outlined for the increase from 4% to 7%. Long range, of course, there will be some offset due to the deduction of the 10% credit from the depreciation base. The arithmetic works out this way for Commonwealth Edison Company:

First, the $17 million investment tax credit anticipated for 1975 would be increased from $17 million to $30 million by going from 4% to 7%.

Second, it would be increased to about $43 million by going to 10%.

Third, the $13 million improvement between $30 million and $43 million, resulting from the increase from 7% to 10%, would be offset, over the life of the plant involved by the $13 million tax value of the depreciation deductions lost. However, time is money, and the depreciation deduction loss would be stretched out over a considerable future period. On the balance, therefore, we would benefit by having a 10% credit with the depreciation change rather than a 7% credit without the depreciation change, but the benefit would not be as great as if we were not required to deduct the 10% investment credit from the depreciation base.

THE NEED TO IMPROVE INTERNAL CASH GENERATION

I said a moment ago that it is essential that internal cash generation be significantly improved if we are to solve the industry's future financing problems. This is brought out in some detail in the first four exhibits I have presented to the committee—exhibits representing the draft report of our Technical Advisory Committee on Finance. It is significant that during the past 15 years, the portion of the electric industry construction program financed internally has been reduced from 59% in the early 1960's to 36% in the early 1970's. These figures are set forth in Table 2 of Chapter I (Exhibit D). In the case of Commonwealth Edison alone we were able to generate all of our construction funds internally in the early 1960's while today, even though we are generating nearly $300 million of cash internally a year, that is not enough to cover half of our yearly construction expenditures.

What can be done about this? There are many possibilities, one which seems to me to be important is to improve our ability to plow-back retained earnings —not to pay most of them out in dividends. As a practical matter this is how mos U.S. industries finance their expansion and modernization. The automobile manufacturers, the steel companies, Xerox, IBM and others retain the bulk of their earnings in the business, reinvesting it and paying out 30% or less in dividends. For the electric power industry, this alternative is virtually unavailable because more than half of our stock is owned by small stockholders who rely upon their dividends to help pay their living expenses. However, if these small stockholders could be encouraged to reinvest their dividends in our business tax-free, such reinvestment to be taxed as a capital gain rather than as ordinary income when sold, or could be allowed to elect a tax-free dividend option, I believe that we could solve a third to half of the electric power industry's common equity fund raising problem—our most serious financial problem. This proposal is described in detail in Exhibit B (recommendation #6, page 5). I believe it is a practical approach to ensuring that we will have adequate electric generating capacity in the years to come.

Also, the continuation of the rapid write-off of pollution control equipment, with applicability extended to equipment placed in service prior to December 31, 1973, would also enhance internal cash generation.

Finally, and most importantly, regulatory bodies must continue to recognize the need for prompt and adequate rate increases to meet costs which have *already risen!*

IV. The effect of a recession on the electric power industry's financial problems

The immediate effect of any decline in peak period electricity usage will of course be to ease some of the industry's fund raising problems. However, business recessions are not all that selective. The reduction in overall sales resulting from slackened business is likely to be greater than the reduction in system peak loads because the first things that get reduced when times are bad are the second and third shifts—and possibly the off-peak air conditioning usage!

Having lived through the depression of the 1930's, it seems to me that the problem of raising any money at all during a depression—a real depression—is so great as to offset the temporary relief we might have from not having to raise quite as much if our load growth slackens somewhat. And the financial effect of a reduction of 5 or 10 or 15% in sales will far offset the benefit of a likely less significan reduction in peak usage. Also, it is hard to shut off carrying charges on already completed plant, even though it may not be required for a time!

It is too soon to say whether the present recession is hurting us or not but I think that if it continues for long, it is bound to do a great deal of damage because, unlike many industries, most of our costs are on-going cost. Most of our expenses are expenses related to the investment in fixed facilities—interest, depreciation, *ad valorm taxes* and requirements to meet other fixed obligation such as preferred stock dividends. These do not cease if business slackens, and people who are out of work are not sympathetic to rate increases needed to take care of financial expenses resulting from plant construction which has long been completed.

This will be the real problem with the electric utilities if our depression becomes extended. We will find it increasingly difficult to get the rate increases needed to cover the commitments we have already entered into. Under these conditions, I would not be surprised if several major electric power systems were to find themselves in serious financial difficulty or even bankrupt.

V. Recent generating station construction delays and cancellations

Numerous studies have been made of the recent delays and cancellations of generating station construction projects. The latest studies I have seen indicate that the delays and cancellations have affected over 120,000 megawatts of generating capacity (possibly as much as 150,000) and that the resulting reductions in construction expenditures have been about $16 billion for the five years, 1974–1978 inclusive. This is equivalent to a cutback of over 1,000,000 man-years of labor effort or between 150,000 and 200,000 jobs throughout the five year period, principally in the already depressed construction industry. In the case of Commonwealth Edison, we have reduced our own estimated construction expenditures for that five year period (1974–78) from an original figure of $4.9 billion to a figure of 3.8 billion, and as stated earlier, our estimated program is now $4.3 billion for the five years ended 1979.

There is no question that some of the delays and cancellations have resulted from the inability of electric power companies involved to finance. This, it seems to me, is very likely to have been the case for companies which have made repeated reductions in their construction programs, for example, Philadelphia Electric, Consolidated Edison, Consumer Power and Detroit Edison. In the case of Commonwealth Edison, we have not found it easy to finance but have not yet been faced with the need to cut our construction programs back because of our inability to finance. Our own reductions, while certainly affected by financing consideration, have reflected reduced load estimates for the future.

THE IMPACT OF THESE DELAYS ON ULTIMATE CONSTRUCTION COSTS

With construction cost continuing to escalate at an annual rate of 10% (or more), there is no question that in terms of inflated dollars, the ultimate costs of the plants will be higher than if the delays had not occurred. On the other hand, aside from the additional interest expense incurred as a result of the stretched out construction schedules, the cost in real dollars will probably not be significantly increased by the delays.

EFFECT OF THE DELAYS UPON RELIABILITY OF SERVICE

With respect to Commonwealth Edison Company, I believe that my answers are already clear. Our construction program stretch-out has resulted from reduced estimates of future loads. Assuming that our load estimates prove to be resonably accurate, the effect of the stretch-out should have no significant effect upon reliability of service. However, I doubt very much that I could say the same for the rest of the industry. Also, unless measures are taken promptly to help us finance, and to stop treating us second-class citizen for tax purposes, we too at Commonwealth will be in trouble.

EXHIBIT A

THE REPORT IN BRIEF

During the next 15 years, estimated expenditures by the electric power industry for new facilities will total $650 billion and external financing will total $650 billion and external financing will reach $400 billion—$15 billion a year during the next five years alone, up from the present level of $10 billion a year.

External financing by the industry is expected to remain at its present level of 1% of GNP, and possibly decline slightly if conservation or load-levelling efforts are successful. During the past five years, it increased from ½ of 1% of GNP to 1%.

The electric industry's immediate financing problems are formidable. Sales of common stock alone must total $3 billion a year during the last half of the 1970's. The financial condition of some firms is desperate. However, the long-run outlook for the industry as a whole allows some cautious optimism, *but* *only if general inflation is brought under control and presently needed rate increases are granted promptly*—and assuming adoption of the following recommendations:

Electric utility managers must pay strict attention to cost control; their objective must be to hold further electric rate increases to a minimum consistent with the public's need for energy and economic resource allocation.

Electricity rates must be high enough to recover costs and attract the capital needed to finance the nation's expanding need for electric facilities. Today's levels appear inadequate in many instances.

The public must be made aware of the critical need for adequate rates. This is of particular importance if the industry and its regulators are to be able to deal promptly and adequately with the effects of inflation.

Rate structures must be modified to trim peak loads, stimulate usage during the nighttime, weekend and seasonal valleys, and encourage conservation of capital as well as energy.

Regulatory processes must be streamlined to deal with inflation.

Tax policy must be modified to stimulate and reward individual savings and investment, possibly by allowing the tax-free reinvestment of dividends. Discriminatory tax policies must be reformed and bookkeeping practices modified to increase internal generation of funds and reduce the need for outside financing.

Environmental policies must give careful consideration to both costs and benefits.

The capital needs of publicly-owned systems must be recognized; their financial integrity must not be eroded by budget or financing restrictions, nor their ability to participate in joint ventures unreasonably impeded.

Exhibit B

Highlights

Over the 15-year period beginning in 1975, electric power industry programs to expand the nation's energy resources and maintain service reliability will require expenditures of approximately $650 billion (reflecting future inflation).

Even though the industry's growth in the next decade and a half is expected to be somewhat slower than in the past, *the $650 billion figure is approximately four times the amount of the industry's present net investment in plant facilities.*

To meet its obligation to carry out a construction program of this magnitude, *the electric industry will need to raise $400 billion in the security markets—again reflecting future inflation. This is four and a half times the money raised in the capital market for industry construction requirements over the past 15 years.*

Although the $400 billion financing estimate is unprecendented, an encouraging note is that it represents a levelling off of the industry's external financing at its present level of 1% of Gross National Product, after having doubled from about half this rate over the past five years. *The possibility that electric utilities' financing requirements may decline in proportion to GNP—if conservation efforts to limit peak load growth and fill off-peak valleys are successful—provides further reason for guarded optimism.*

BASIS OF FINANCING ESTIMATES

All projections used herein reflect the anticipated effects of future inflation. Projected expenditures and financing requirements of the industry are based on the assumption that growth in the use of electric energy will be at annual rates ranging around 6% over the next 15 years, rather than at the historical rate of 7%. This assumption appears to be valid in view of the urgency to achieve U.S. energy independence and the role electric energy will have to play in achieving this goal, on one hand, and in recognition of the effects of capital limitations, conservation efforts, and price elasticity on the other. Also the near-term possibility of a continued business slowdown cannot be ignored.

Money requirements, in any event, will be materially affected by the success, or lack of it, resulting from efforts to bring inflation under control.

This study of the Technical Advisory Committee on Finance is concerned with developing recommendations to help overcome the acute financial problems confronting the electric power industry and to enable it to raise the large amounts of money required for construction of new plant facilities to meet the growing electric energy needs of the public.

FINANCIAL PROBLEMS

The financial problems of the industry generally relate to the effects of inflation on construction and money costs, the insufficiency of capital resources, the long lag in translating higher costs into higher electricity prices and the resulting disenchantment of the investment community.

Since the late 1960's, construction cost escalation and greater plant requirements have increased the need for capital sharply while internal cash generation has lost momentum. As a result, external financing needs of the electric industry rose from ½ of 1% of GNP in the 1965–9 period to 1% of GNP in the early 1970's.

Today, the financial condition of some utilities is critical. In a few cases, added capital needs cannot be financed. In many instances emergency rate increases are being requested.

Longer run, however, there are indications that the industry's capacity to generate funds internally may increase sufficiently—aided by cost-compensating rate increases—to halt to rise in the rate of external financing in relation to GNP. *With continued governmental and regulatory recognition of the industry's capital requirements (and assuming realized future earnings on common stock at the 14% level) it is reasonable to expect future external financing needs of the industry to continue at roughtly the 1% GNP level.*

This Committee believes there is some basis for optimism if levelling off of industry financing at 1% of GNP can indeed be achieved. However, further drastic efforts will be required to maintain financing at this level and to avoid additional increases in the future.

To begin with, there is the obvious necessity for appropriate and timely rate increases in order to encourage and justify investment in electric utilities' securities. At the same time, the electric power industry's reliance on the capital markets must be minimized. Steps must be taken promptly to increase the industry's capacity to generate more funds internally—steps such as higher depreciation rates and additional tax credits related to new plant investments. It is essential to reverse the decline in system load factors by adopting measures to slow the growth in system peak loads and fill nighttime, weekend and winter load valleys. Many measures proposed herein to help the industry meet its financing obligations in the next 15 years have this critical need in mind.

Finally, steps must be taken to halt inflation—which hits electric utilities especially hard because they cannot readily adjust prices to rising costs, nor can they overlook their responsibility to maintain, improve and expand the increasingly expensive facilities needed to keep customers supplied with electric energy.

RECOMMENDATIONS

Discussed more fully within the text of the report, the Committee's principal recommendations to improve financing capability are as follows:

1. Strictest attention must be given by all utilities to cost control. Expenditures must be pared down to those essential to providing reliable service and conducting farsighted research programs which will ensure the continued technological progress essential to minimizing future electricity price increases. A major objective of utility managements must be to hold the need for electric rate increases to a minimum level consistent with the public's need for adequate energy supplies and at the same time consistent with the principle that only cost-determined prices will result in the most efficient allocation of scarce energy resources.

2. Total revenues must be adequate to compensate for rising costs, maintain favorable credit ratings and provide a competitively attractive base for marketing stocks and bonds. Today's money markets indicate that fixed charge

(interest) coverage ratios aid common stock equity returns are generally inadequate to enable the industry to continue meeting its financial obligations.

3. The public must be made aware of the critica need for revenue and earnings levels to be adequate to attract capital in competition with other demands for capital funds, public as well as private.

4. Rate structures must be modified to relate the prices of electricity more closely to costs in order to discourage peak use, to encourage off-peak use, and to conserve our scarce capital resources.

5. Regulatory processes must be streamlined and pricing policies adjusted in a realistic and timely manner to prevailing financial conditions.

6. The government must adopt a broad policy of stimulating and rewarding savings and investment. Tax exemption for dividend reinvestment could, for example, provide a third or more of the industry's total needs for new common equity capital which are estimated to be $3 billion a year for the next five years. In addition, taxing policies and laws which discriminate against the industry or discourage investments in its securities must be reformed. New tax burdens must not be imposed on the industry.

7. Accounting practices which facilitate internal cash generation must be the rule rather than the exception.

8. Increased attention must be given to the relation of costs to benefits, particularly in areas of environmental protection.

9. Although federal or state financial aid for specialized needs, such as pollution control, appears helpful for the short term, its expansion would not eliminate the need for fair and proper electric rates and might aggravate the capital-raising problems of state and local governments.

10. The capital needs of publicly-owned systems—federal, state and local—must be recognized in the establishment of government budgets. Institutions like the Federal Financing Bank and the National Rural Utilities Cooperative Finance Corporation are already providing constructive help to federal and cooperatively owned utilities. Judicious expension of such institutional aid to other sectors may be desirable.

11. Companies or agencies within the industry should continue to take advantage of joint ownership and financing arrangements where warranted by the resulting economies of scale. Statutes and regulations which preclude or unreasonably limit the financing and organization of such arrangements must be reformed.

12. Alternatives to those presently used should be explored to provide for "allowance for funds used during construction." One such alternative might be to include all or a portion of plant under construction in the rate base.

OTHER POSSIBILITIES

As previously indicated, the industry's estimated expenditure of $650 billion (future dollars) over the next 15 years is predicated upon a moderate growth case with moderate environmental expenditures. However, this estimate could be modified downward to reflect possible near-term effects of conservation and slackened business. The Committee has submitted various other possibilities projecting expenditures from as low as $100 billion for a "zero growth" outlook to over one trillion dollars for an all-electric economy. Factors that *will have the most important influence on actual construction expenditures and financing needs from now through the 1980's will include growth in peak demand, growth in total usage, the rate of inflation, environmental requirements, tax provisions and the level of general business conditions.*

RECENT CONSTRUCTION CUT BACKS

During the year 1974, progressively large reductions in projected construction expenditures have been announced by the electric power industry, reflecting reduced load growth projections but also affected to an important degree by financing difficulties. As this report is being completed late in 1974, these construction delays and cancellations have affected about 125,000 megawatts of generating capacity (much of it nuclear) and have reduced anticipated constrution expenditures for the five years, 1974 to 1978 inclusive, by about $16 billion. This is equivalent to a cut back of over 1,000,000 man-years in labor effort or between 150,000 and 200,000 jobs throughout the five-year period, primarily in the already depressed construction industry.

Exhibit C

Introduction and Summary

In the fall of 1974, at the time of preparation of this report, U.S. money markets are in disarray. Interest rates are at the highest levels since the Civil War and stock prices have been declining for several years. There are notable shortages of capital in certain important areas, as in housing. There is a growing feeling of uneasiness that if capital markets continue to deteriorate, it may not be possible to continue to market the large $100 million sized security issues needed in meeting the large future financing needs projected in this report.

Although recent declining stock prices are not peculiar to the electric power industry, its need to market large quantities of new stock, even in a poor market, *is unique*. The ability of utilities to raise capital is a matter of grave concern to the whole community, not just to their stockholders. The electric power industry is the most capital intensive of all. Its financing requirements now represent one-third of all U.S. corporate financing. Also, unlike many, it must raise approximately $3 billion of new common equity funds a year during the next five years. A substantial improvement in earnings will be required if investors will, in fact, purchase this much new issue electric utility stock under today's conditions.

If adequate electric facilities are to be provided to meet the nation's future needs for power, the firms which have to pay for those facilities must not be unduly hampered from raising rates to levels needed to compete effectively for the needed construction funds. This goes for public, private and cooperative firms as well. If the public is to be provided with adequate supplies of electric power in the future, revenues from electricity sales must be sufficient to providecapital-attracting returns—returns higher than attained in the past, because the demands for, and, hence the competition for capial is greater than it used to be.

It is the hope of this Committee that, as has been true for virtually all of the 20th century, technological developments and the careful control of operating expenses will keep electricity rates from rising as much in the next decade and a half as the rate of general inflation, although this may be neither possible nor economically sound. At any rate, in the interest of the public and the nation as a whole, electric managers must be more diligent than ever in the years ahead—continuing to operate so as to minimize non-essential or peripheral expenditures, conducting effective, far-sighted research and development, and continuously explaining carefully to the public the critical need for adequate rates if additional investment funds are to be obtained.

Our concerns in this study have been to review the financial problems of the electric industry and to determine how they can be resolved. We believe that the measures outlined herein can, if adopted promptly, assure the industry's ability to meet its future financial requirements despite further fuel supply problems and slow-ups in the U.S. economy as a whole—but only if general inflation can be brought under control.

I. Recommendations

The primary objective of the Committee's work has been to formulate recommendations which will enable the industry (in its present form[1]) to pay for approximately $650 billion of new construction between now and 1990—approximately $125 billion during the next five years (1975–9) and roughly $525 billion more during the following ten years (1980–1989).

The industry faces several acute financial problems. *First*, construction cost escalation and greater plant requirements are increasing the need for capital, while until recently internal cash generation has lagged behind. Unless effective steps are taken promptly to increase still more the rate of internal cash generation, plant modernization and expansion may have to be financed, to an increasing degree, through the sale of securities.

[1] This report assumes that the structure of the electric power industry, with its private, public and cooperatively owned sectors, will continue in much the same form in the future as in the past.

Second, future competition for capital funds will probably increase, as the demand for capital by other sectors of the economy continues to increase, inasmuch as the savings rate for the economy—the supply of new capital—as a whole tends in the long-run to remain relatively constant. Not only will future private capital demands increase, or at least remain high, but increased competition for capital is likely to develop from government at all levels, and from foreign sources, both public and private. (Government demands on U.S. capital markets have already increased sharply since World War II, from 1½% of GNP in the 1950–4 period to 4% of GNP in the 1970–4 period.)

Third, continued pressure on the capital market could lead to still higher rates of interest and inflation in the future. Under conditions of continuing "double-digit" inflation it would be exremely difficult for utilities to maintain their viability through existing institutional and regulatory procedures. To the extent that inflationary pressures can be brought under control, the financial problems of the industry will be correspondingly lessened.

Measures which the Committte believes will help ensure the industry's financing during the next 20 years are set forth in the following paragraphs. Many of these measures have as a major purpose increasing internally generated cash and reducing electric power firms dependence upon our strained capital markets. Others are designed to encourage individual savings and investment.

(1) *Cost control.*—Utilities must continually review their operations to assure that expenditures are at a minimum consistent with reliable service. Quality and reliability of service should also be studied to determine whether savings can be realized without undue adverse impact on customers. We are no longer a cadillac society—and electric customers may well prefer not to have cadillac service.

(2) *Adequate revenue levels.*—It is clear that the industry (public and private) must be able to pay the new higher interest costs on the additional debt money needed. It is also clear that in order to maintain its credit ratings, the investor owned sector must rely heavily upon common equity financing in the future. This will require earnings sufficient to sell common stock at prices which will not dilute the investment of existing holders and will provide a reasonable margin of safety beyond that, because investors are unlikely to be attracted to the common stock of a firm which has turned its back upon existing shareholders.[2] It is relevant to observe that return on common equity is only about one-tenth of total electric revenues, accordingly relatively modest rate increases would produce material improvements in earnings on common stock. Failure to take steps necessary to provide revenues adequate to attract additional capital without diluting the value of outstanding securities would pose major service and economic problems for the public and spell financial disaster for the industry. This is true for all sectors of the industry—private, public and cooperative.

(3) *Public awareness.*—The public is generally unaware of the pent-up need for electric rate increases to catch up with inflational cost pressures. Electricity prices resisted the effects of moderate inflation for so many years that the public is understandably impatient and angered now by repeated rate requests necessitated by today's unfortunate combination of high construction costs, high interest rates, costly environmental, safety and licensing requirements and sharply increased fuel costs. In combination, these have resulted in accelerating costs which have often piled one electric rate increase on top of another. The resulting political pressures have slowed the regulatory processes; in some cases, even government take-over is threatened, and there is mounting concern in the investment community—all of which compound the problems.

It is clear that today's electric power managers have an overriding responsibility to inform the public—both customers and stockholders—of the financial problems their industry faces. Also, there was never a time when skillful, cost-conscious, far-sighted management was more urgently called for.

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[2] During the fall of 1974, earnings-price ratios applicable to common stocks of firms in the electric power industry are in the 15 to 20% range, which corresponds to price-earnings ratios in the five to seven range.

(4) *Modified rate structures.*—Rates should more adequately reflect current as opposed to historical costs. Flattened rate structures, peak load pricing and interruptible rates should be encouraged in order to align rates more closely with costs and thus help assure the more efficient utilization of resources. However, better elasticity studies than those now available are needed to determine the precise impact of rate design on demand, and the extent to which rates reflecting the marginal costs of providing service will be effective in filling valleys, shaving peaks and encouraging the economic use of energy.

(5) *Minimizing regulatory lag.*—A variety of methods have been suggested for speeding up rate regulatory processes, including (i) the greater use of automatic price adjustment clauses, particularly fuel cost adjustment clauses; (ii) the use of year-end rate bases and future test periods (using forecasted financial data rather than historical data to establish rate levels); (iii) the use of expedited proceedings to provide interim or emergency rate relief, possibly not subject to later refund; and (iv) the establishment (where not now provided for) of statutory deadlines for prompt resolution of rate issues. Although the members of the Committee are not of one mind as to which, if any, of these methods would be appropriate, there is general agreement that electricity price levels must be promptly responsive to changing costs.

(6) *Tax reform.*—The government must recognize the need both to stimulate savings and to mitigate the effects of existing tax impediments which penalize the capital intensive industries (such as electric power), discourage plant modernization and expansion, and make its financing difficult.

Suggestions for modifying individual taxes to stimulate savings and investment in productive facilities include dividends reinvested in stock of the same company; the deductibility or partial deductibility of dividends on stock, and various proposals to encourage investment in polution control equipment. Allowing tax-free dividend reinvestment or the tax-free receipt of optional stock dividends would go far toward providing the added common equity funds needed.[3]

Suggestions for modifying corporate taxes include a 10% investment tax credit for the electric power industry (similar to that recently proposed by the President for industry in general) and the further acceleration of depreciation deductions to help finance new long-lived plant construction.

(7) *Accounting practices to maximize internal cash generation.*—Provisions for book depreciation should be increased to reflect realistically economic lives of 20 years or less for most classes of property. This would help provide for the very real costs of rapid technological and economic obsolescence which shorten useful lives and, when reflected in rates, this will also enhance internal generation. Other accounting practices which should be similarly employed to maximize the internal generation of funds include (i) the current expensing of charges which need not be deferred and (ii) the so-called "normalization" of federal income tax benefits related to plant investment, by deferring such benefits, i.e. spreading the tax benefits attributable to the acquistion of an asset over the useful life of the asset in question.[4]

(8) *Increased attention to conservation of energy and capital recourses; also to the benefits and costs related to environmental requirements.*—A conscious effort must be made by managers, regulators and the public to conserve both energy and capital to the fullest extent practicable. We are becoming a capital-short society—as well as an oil-short one. Consequently expected costs and benefits must be carefully evaluated before new capital burdens are imposed upon society. For example, the costs as well as benefits

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[3] Estimates are that between one-third and one-half of the investor-owned sector's new common equity money needs could be provided by tax free dividend reinvestment or the tax-free receipt of optional stock dividends.

[4] The so-called "normalization" of income tax benefits refers to the accounting practice of spreading certain tax benefits related to a plant investment over the useful life of the plant in question. This applies primarily to (i) tax reductions resulting from application of the investment tax credit when an item of equipment is acquired, and (ii) tax deferrals resulting from deducting either accelerated depreciation (in excess of book depreciation) or pensions, payroll taxes and interest expense (where capitalizd for book purposes but not for tax purposes). The procedure followed in accounting for such "normalization" is to charge operations at the outside with the amount of tax benefit to be deferred, crediting an appropriate reserve account with the same amount. The amount in the reserve account is then amortized over the useful life of the related plant investment, crediting operations and charging the reserve with a pro-rata portion each year.

of each environmental protection proposal should be fully recognized and accepted. Added costs should be imposed upon the public only to the extent commensurate with demonstrated benefits.

(9) *Higher equity ratios.*—Many Committee members believe that, in the future, the industry must rely upon a higher degree of equity financing to assure its continued ability to attract capital. Their reasoning is that such increased equity financing is necessary to raise the fixed charge coverage ratio.[5] Because of higher rates, such coverage ratios have dropped sharply in the last ten years. It is unrealistic to assume the investment community will become reconciled to the new lower coverages. On the contrary, permanently lower coverages will result in still higher interest rates and may cause some security issues to be unmarketable.

(10) *Institutional changes.*—Federal or state financial aid for specialized purposes, such as pollution control facilities and conversion to domestic fuels, is important in the short run. In the long run, however, it is not a satisfactory substitute for setting electric rates high enough to cover reflect and to cover the full costs of supplying electricity.

(11) *Joint financing.*—In some cases, joint ownership of expensive new generating plants may facilitate the financing of plants which would prove too large for a single company unreasonable governmental restrictions on the ability of electric power companies and public agencies to structure such joint ventures should be modified.

(12) *Allowance for funds used during construction.*—A large proportion of electric power company earnings is now represented by credits for the financing cost of construction work-in-progress—commonly labelled "allowance for funds used during construction." Consideration should be given to including all or a portion of plant under construction in the rate base, thus raising revenues sufficiently to cover the cost of money employed during the construction period. Also, consideration should be given to changing accounting and reporting methods to avoid passing the interest and preferred dividends applicable to plant under construction through the income account. At a minimum, every effort should be made to assure that the amounts recorded for such "allowance for funds" are adequate (but no more than adequate) to cover the real financial costs thereof.

II. FINANCIAL NEEDS [6]

The Committee has promised its consideration of future financial needs on the assumption that industry structure—its private, public and cooperatively owned components—will continue to exist in the future much as it has in the past. The Committee estimates that the electric power industry will spend about $125 billion on new construction during the last half of this decade (1975–79), one and one-half times the $84 billion spent during the first half of the 1970's (1970–74). Expenditures during the 1980's may or may not continue to accelerate at a comparable rate. The Committee is of two minds on this.

In order to finance the industry's contruction expenditures, $15 billion or more of new money will be required each year during the last half of the 1978's. These compare to less than $10 billion a year in the recent past.

The electric power industry is the most capital-intensive of all major industries, requiring nearly one-third of all the new capital funds raised in the money markets by U.S. industry. Within the last few years, the electric power industry's new money needs in relation to the gross national product have been using. It now appears, however, that this proportion may level off, or even decline moderately in the 1980's. The relatively constant rate of savings in our society emphasizes the importance of taking steps to ensure that this is accomplished. However, its achievement will depend upon substantially increasing the present rate of internal cash generation.

Future projections. The Committee's estimates of future construction expenditures and new money needs were developed using a comprehensive mathematical model. As with any projective technique, a number of assumptions were made with respect to sales growth, plant utilization, generation

[5] Fixed charge coverage is generally defined as the ratio of earnings available for interest and other fixed charges to the amount of such charges. For a technical definition, see the Glossary.

[6] Expressed in "future dollars"—see Glossary.

fuel mix, tax structures and the like. An important assumption affecting the proportions was that actual annual earnings on common equity, expressed as a percentage of book value, will be on the order of 14%.

Some of the assumptions were based on recent experience any assurance that they would prove correct.

The assumptions as to load growth, construction cost escalation and environmental expenditures were deliberately varied to produce eight possible cases [7] and also to provide an analysis of the sensitivity to changes in various future developments. A wide array of possibilities was selected in order to reflect a variety of opinions among Committee members as to what is most likely to occur. For these varying cases and sensitivity analysis, a range of values was used to accomodate the various opinions among Committee members.

A detailed description of the model, along with the input assumptions and the outputs is set forth in Appendix A of the report. The model was tested by using it to approximate retroactively the industry's financial requirements for several years prior to 1970, and such approximations were found to be reasonably close to actual data for those years. The estimates of possibilities for future years under various cases were compared to other published estimates, and the "middle ground" cases were found to be resonably close to these estimates. Although such comparisons do not prove the correctness of the forecasts, they lend them a degree of credibility.

A summary of the expenditure and financing projections for the eight cases follows:

[In billions]

	Construction expenditures		External financing [1]	
	1975–9	1980's	1975–9	1980's
Case I, "moderate growth," with high escalation of costs and high environmental costs	$134	$566	$83	$337
Case IA, same, with low environmental costs	116	537	70	323
Case II, "historic growth," with high escalation and low environmental costs	129	685	78	431
Case III, "low growth," with low escalation and high environmental costs	90	261	47	116
Case IV, "all-electric growth," with high escalation and low environmental costs	163	1,172	107	797
Case V, "zero growth," with low escalation and high environmental costs	32	77	(2)	(3)
Case VI, "topping-out," with low escalation and high environmental costs	110	162	63	28
Case VII, modified "topping out," same, with slower decline in growth	71	183	30	64

[1] All figures reflect future inflation, being expressed in "future dollars"—see Glossary. "Construction Expenditures" include the cost of replacing worn-out plant. "External Financing" excludes refundings. Approximately 20 percent of the estimated external financing would take the form of new public offerings of common stock by investor-owned firms, unless dividend reinvestment can be increased substantially through tax incentives.

Preferred projections.—The results yielded by cases IV and V, the "all-electric" and "zero growth" cases respectively, fall beyond the range of reasonable expectation. Therefore, the Committee believes that the remaining six cases form the outside parameters of likely future requirements. A majority of the Committee feels that case IA–moderate" growth coupled with moderate environmental expenditures—presents a balanced view of likely possibilities which might serve as a base from which to consider possible alternatives and variations and which will be useful to private and public planners faced with the practical needs of policy formation and decision-making. However, near-term projections may be moderately lower than those in case IA, reflecting a probable continuation of slack general business in 1975 and possibly thereafter, together with the likelihood that conservation efforts will increase in the last half of the 1970's. Moreover, wide variations from the possibilities presented by case IA may occur for other reasons and are indeed likely. For examule, 15–year environmental expenditures alone range from $18 billion [8] in case IA to $59 billion in case I—the "high" environmental cost care. Hence the need to examine all the cases carefully.

[7] These eight sets of future possibilities are described briefly in Chapter I and in detail in Appendix B.

[8] Subject to changes in U.S. EPA.

Future levels of electricity prices.—This survey makes no attempt to predict the future level of electricity rates or the probable form of such rates. To have properly treated the matter of rate structure and form would have required significant studies of price elasticity and cross-elasticity which we felt beyond the scope of our study. Moreover, in view of the wide diversity of opinions on this complex subject, it may have been impossible to arrive at a consensus as to either the preferred or the likely forms of future electricity rates.

As a matter of fact, future rate levels will be affected by a number of uncertainies whose effect on rates may be far greater than that of the variables considered in this report. These major uncertainies include such matters as fuel prices, interest rates and state and local tax levels. Who can say what the oil exporting countries might decide to charge for oil next year? Who can say what the level of interest rates may be even within the next few months? Who can say what taxes may be levied in the future?

III. IMPORTANT FACTORS AFFECTING THE ESTIMATES

(i) Future growth

The growth rate in peak demand for electricity is the single most important factor affecting future construction expenditures and new money needs. Whether or not peak demand and total electricity usage will grow at the same rates remains to be seen.

Recent developments.—The past year has seen a marked slowdown in both total usage and usage at the time of the system peak for virtually all of the U.S. electric power systems. This slowdown has resulted partly from a slackening of general business, partly from conservation, partly from mild weather conditions and partly from a reduction of usage due to higher prices of electricity, particularly in areas served by oil-fired generation. Consequently there is considerable uncertainty as to whether the change represents a modification of long-run trends or a temporary phenomenon.

There is considerable uncertainty for example, as to whether the current business recession will deepen—and how long it will continue. Also, the current national emphasis on conservation will almost certainly dampen the rate of growth in electricity usage. This has already been experienced in varying degrees—although there may well be a countervailing tendency to substitute electricity for other forms of energy in short supply. Finally, if electricity prices rise faster than the cost of living generally, some dampening of growth due to this factor as well would be likely to occur.

These factors may well have a greater effect upon the total volume of usage than on peak period level of usage. Hence, the slow deterioration of system load factors which has characterized the last decade may well continue—at least until such developments as electric space heat and nighttime battery charging begin to fill the valleys. For purposes of this study, however, the Committee has assumed that peak loads and total usage will grow at about the same rates in the future and that system load factors will remain at approximately present levels.

The Committee is divided as to whether the current slowing of growth will be temporary or whether there will be a permanent reduction in long-term growth rates. The eight cases, therefore, reflect various assumptions as to rates of growth.

We have examined the effects of a "zero growth" assumption, as well as the consequences of other growth rates including an "all-electric" assumption which could result from substitution of electricity generated from coal or nuclear fuels for residential, commercial and industrial uses of oil and gas and other forms of energy in short supply. In our view, substantial amounts of electricity may be required to reduce the nation's reliance upon other forms of energy in more limited supply, and this shifting will preclude achievement of zero growth. On the other hand, the Committee is equally reluctant to accept the likelihood of the other extreme—the "all-electric" growth scenario.

(ii) Future inflation

Electric plant construction expenditures in constant dollars have been growing substantially faster than GNP measured in a constant dollars. Moreover, in recent years, the rate of construction cost escalations has been greater than that of general inflation. Thus an increasing portion of GNP has been required to pay for electric plant construction. If this continues, the electric power industry will face ever-increasing competition for construction funds, under-scoring the extreme difficulties the industry will confront if inflation is not brought under control.

All of our projections assume that after 1980 general inflation rates will be held to the three to five percent annual range and that construction costs will escalate at similar rates. *If these assumptions are unrealistically optimistic, then our guarded optimism for the long-run future will have been unwarranted.*

(iii) Environmental expenditures

The major objectives of the national environmental program may be broadly classified as (a) protection of the nation's air resources so as to promote the public health and welfare, and (b) restoration and maintenance of the chemical, physical and biological integrity of the nation's waters. Although the electric power industry will invest substantial capital in ensuing years to achieve these objectives, the amounts involved are as yet uncertain. First, it is not clear what environmental standards will ultimately be necessary for the long range protection of the environment. Second, there is no certainty as to the type of facilities necessary to achieve these environmental standards; only limited experience is available as to the effectiveness and costs of pollution control systems that may become available. Finally, the extent of exemptions that may be granted from the thermal requirements for condensing water is an unknown and may be determined on a case-by-case basis. The Committee has, therefore, made both "high" and "low" environmental cost assumptions for the future. believing that the alternative estimates presented will be useful in judging future requirements and that, as experience is gained, the range of possible values will narrow. In the moderate growth cases I and IA, for example, 15 year environmental expenditures estimates range from a low of $18 billion [9] (caseIA) to a high of $59 billion (case I).

(iv) Income taxes

Changes in income tax provisions could have an important effect on the external financing requirements of the several sectors of the electric power industry.

Retention of present benefits.—There is perennial discussion about the necessity of retaining—or the possibility of eliminating—certain federal income tax provisions which have been designed to minimize the burdens which such taxes impose on capital investment. These special provisions include (i) the allowance of accelerated methods of computing depreciation deductions under Section 167 of the Internal Revenue Code, (ii) tax regulations establishing "guideline lives" for tax purposes, (iii) so-called Asset Depreciation Range (ADR) provisions of the tax regulations which permit the shortening of guideline lives, and (iv) the investment tax credit provisions of the Internal Revenue Code. To the extent that cash savings resulting from these items are "normalized" [10] (i.e., credited to balance sheet reserve accounts, rather than reflected in earnings and paid out in dividends) they provide the industry with approximately $500 million annually of additional internal cash generation Elimination of any of these provisions would significantly increase the future financing needs of the industry.

New suggestions.—Adoption of serveral additional tax provisions would reduce outside financing requirements.

First, a simple but obvious measure would be to raise the investment tax credit available to electric utilities from 4% to 10% or at least to 7%, the level now available to almost all other industries. Even though some utilities may not currently be in a position to take full advantage of a 7% or 10% credit, this measure would be valuable to the industry as a whole, particularly with some relaxation of the ceiling which now limits the aggregate credit to 50% of taxes computed before the credit.

Second, possible changes in the tax treatment of tax-exempt bonds could affect the financing capability of state or municipally-owned utilities or public utility districts which rely upon such instruments to raise money. These

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[9] Subject to Change by U.S. EDA.
[10] See footnote 4 above for a definition of normalization.

utilities urge that, at least, the tax benefits not be further eroded or the use of such instruments expanded significantly, thus burdening the tax-exempt markets still more.

Third, another possible tax change would be to encourage the reinvestment of cash dividends on common stock by exempting such dividends from tax if promptly reinvested in identical new issue stock. Many small stockholders now rely for their livelihood on the cash dividends on their utility common stock. Consequently, electric utilities do not have available the ready option (available to most industrial firms) of reducing dividend payouts to increase the amount of cash retained in the business. An appropriate change in the tax law would reward small stockholders (who own the bulk of electric utility stocks) for reinvesting their dividends by making such reinvestment tax-free. Tn alternative would porvide for two classes of stock, one paying taxable cash dividends and one non-taxable stock dividends, with a stockholder's option to switch (tax free) from one to another. Some firms estimate that either of these provisions, if adopted, would result in reinvestment of 40% of cash dividends on common stock or in excess of one billion dollars a year if encouraged by all investor-owned electric utilities.

(v) The effect of nuclear power

One important long-run effect of the fossil fuel "energy crisis" may be hasten the swing to nuclear power. We have assumed that by the late 1980's about 60% of all new base-load generating capacity additions will be nuclear. However, if the nuclear percentage actually turns out to be smaller, it will be unlikely to have a significant effect upon total construction expenditures because the cost differential between nuclear and fossil base-load plants is not great enough percentage-wise for a moderate change in the mix to affect our predictions significantly.[11]

IV. FINANCING MEASURES

The nation's future capital needs, considering the requirements of both government and industry, will be great indeed. In addition, capital markets are international and many countries which, as yet, have relatively less capability for saving will also be trying to raise capital. Finally, the debilitating effects of sharply higher international oil payments cannot be overlooked. Therefore, we are concerned as to whether or not the electric power industry will be able to compete successfully with other claimants, both foreign and domestic, for its growing capital requirements, both in terms of attracting new capital and encouraging reinvestment by existing investors.

Capital funds cannot be conscripted—except through taxation—and it is an historic fact that the rate of savings in this country has been relatively constant over the past 100 years. We do not expect that the near-term future will be much different in this respect. It would appear, therefore, that unless internal cash generation can be increased significantly then the electric utilities may have to attract an increasing share of the nation's savings by investors—small as well as large. This will require electric utility earnings levels adequate to complete in the capital markets and to assure investors that future interest, dividend and principal payments will be made and, in the case of common stock, that earnings and dividend levels will be adequate to compensate for losses in value resulting from general inflation. It will also require every effort to be made to follow procedures to maximize internally generated cash and encourage earnings or dividend plow-back.

Institutional arrangements.—The institutional characteristics of electric power entities range from private-investor ownership, which presently provides about 80% of the country's electricity, to cooperative ownership and public ownership. Variations in the public sector include municipal ownership, public utility districts, ownership by state or federal corporation like the New York Power Authority and the Tennessee Valley Authority, and federal government ownership.

There have been suggestions that institutional changes can be of help in solving financing porblems. The Committee believes, however, that institutional characteristics have little effect on the amounts of capital funds needed and that institutional changes would not necessarily result in significant differ-

[11] This is especially true after reflecting possible stack gas clean-up costs. See Exhibit I at close of Chapter I.

ences in the sources of these funds. Almost any form of institution—private or public—can issue short term and long term debt, and most utilize equity funds in some form. Funds contributed by the federal Treasury to special federal corporations are, for example, in many ways akin to equity. And equity funds are customarily provided by members of electric cooperatives.

Government Aid.—In spite of recent price increases, electricity prices have not risen as much as those of other commodities. In fact, electric bills take about 1.5% of consumers' expendable income today, about the same as 25 years ago.[12]

In general, it is the Committee's view that consumer of electricity ought to bear the full costs of producing what they use.[13] Under conditions of rapid inflation, however, the public may express reluctance to accept the higher electric rates required to attract capital. This is true today. As a result, various forms of government aid have been suggested.

The use of government-financed generating facilities and the use of tax exempt financing are examples of such aid already in use. In addition, it has been proposed that the government might ensure or guarantee utility debt, thus making possible greater industry reliance upon debt financing at a lower cost. One specific proposal in this regard would provide a government guaranty to electric utility loan applicants who could give "reasonable assurance" of payment of the indebteness.[14] Without adequate earnings coverage of its debt obligations, no utility could provide such assurance. Because interest rates on government-backed securities are also at historic highs, the issue of government guarantee debt would not, in itself, improve interest coverage significantly. Adequate earnings on adequate amounts of equity would still be necessary to provide the proper coverage and would be a limiting factor on the issue of government-guarantee debt as it is with conventional debt. Under these conditions, the government guaranty of debt would do little to diminish the risks facing equity holders and thus would contribute little to solving the problem of raising essential equity, a serious problem in the industry that has been dramatically illustrated recently.[15]

The Committee does recognize the possibility that emergency, or near-emergency, circumstances may arise out of the international petroleum situation, and out of related policies that may be developed should certain contingencies come to pass—and that such circumstances may rapidly increase or accelerate the capital needs of the industry. Principal among these might be a need to develop domestic alternatives to imported petroleum, including gasification, liquification or desulfurization of coal and lignite. Such measures might well entail outlays at speeds and under circumstances of risk that could not easily be managed by the utility industry as it is now structured. In that event, it might be useful or necessary to develop federal mechanism for financing and carrying the risk of needed facilities, on a temporary basis, much as was done in World War II in such industries as aircraft, ship-building and ordnance.

Higher depreciation rates.—Investor-owned utilities now provide book depreciation at rates approximating three percent a year. Several federal hydroprojects provide depreciation at a rate of less than one percent a year. The Tennessee Valley Authority uses 2½% a year. Rates used by municipalities and rural cooperatives generally fall in the 2% to 3% range. These rates might have been adequate under conditions of stable prices, abundant fuel supply, moderate technological change, predictable environmental requirements and fully reflected social costs, but none of these circumstances holds today, nor do any seem likely for the foreseeable future.

If book depreciation rates were increased to five percent annually and guideline tax lives correspondingly were reduced to 20 years or less—which is by no means inappropriate in view of the rapid price rises and obsolescence experienced by the industry in recent years—annual internal cash generation would be increased by approximately $2½ billion. The need for outside financing would be correspondingly reduced.

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[12] Questions and Answers about the Electric Utility Industry, Edison Electric Institute.

[13] If public policy should decide to subsidize any category of consumers or selected industries, this Committee believes that such subsidy should be handled directly and should not be concealed by use of favoring power rates. Subsidies hidden in preferential rate schedules encourage (and hide) uneconomic allocations of energy and capital.

[14] William L. Rosenberg, "Rates, Consumer Pressure and Finance: The Need for Innovation in Electric Utilities," an address to the Annual Convention of the National Association of Regulatory Utility Commissioners, September 18, 1973.

[15] See Chapter II.

Dividend payouts.—Cash dividends on electric utility common stock currently amount to 2.6 billion annually and dividend payout ratios average about 70%. Such payout ratios are high as compared to U.S. corporations as a whole. In theory, a reduction in payout ratios to 50% would increase internal cash generation approximately three quarters of a billion dollars a year at present levels of earnings. Electric utility managements are, however, under great pressure to maintain high dividend payouts to retain the attractiveness of their stock to the hundreds of thousands of small investors who rely on their dividends for personal income. Consequently, the continuation of high payouts is essential, given the need to sell large additional amounts of equity in the future. The effct upon utility stock prices of Consolidated Edison's announcement that it was passing its second quarter 1974 dividend amply demonstrates the importance of dividends to today's investor in electric utility stocks. The market price of Consolidated Edison stock declined over 50% during the first month following the announcement, and the Dow Jones utility average dropped about 12% in the same period.

Because many utility stockholders now receiving dividends are those who would buy new issues of common stock, some members of the Committee believe that the utilities should give further consideration to the use of stock dividends in lieu of cash. One possibility which would conserve cash and yet atteract investors who demand current income but might be willing to postpone its receipt would be a utility common stock with optional cash or stock dividends—or alternately a tax-free dividend reinvestment plan. The optional tax-free stock dividend has been used with some degree of success in the past but neither it nor tax-free dividend reinvestment is permitted under present tax laws.[16] A change in such laws was suggested above.

V. NECESSARY REGULATORY RESPONSE

Regulation of financing.—Meeting the electric power industry's large future capital needs will require flexibility, adaptability to changing capital markets and the best use of innovative financing arrangements by the industry. Meeting these needs will also require rsponsiveness to new circumstances. Regulation of financing should continue to be prompt, flexible and sophisticated. The interests of consumers must be protected and appropriate government supervision maintained, but advantageous financing alternatives should not be restricted by traditional procedures which may no longer serve the public interest. It may have been appropriate at one time, for example, to require that all long-term debt and preferred stock financing be bid competitively. But in today's quickly changing markets there are instances when the ability to place securities quickly, without bidding, may enable a borrower to take advantage of a short-lived dip in interest rates and thus save money for customers and stockholders. Moreover, in today's capital markets, the investment community occasionally has difficulty forming more than one selling group for a large security issue. When that occurs, *bona fide* competitive bidding is impossible.

Regulatory lag in rate setting.—Much has been said about the deleterious effect of regulatory lag upon a firm's ability to attract capital, as well as its possible effect as a stimulus to managerial efficiency. We believe that failure to eliminate or substantially reduce traditional regulatory lags, considering today's rapid inflation, will result in further reduction of the electric power industry's credit ratings and will increase the difficulty and cost of financing. Managerial efficiency is probably better promoted by means especially designed for the purpose.

Economic pricing and conservation.—Much has been said elsewhere in this report of the need for proper design of electricity rates to reflect the true cost of providing service (on-peak and off-peak), to encourage conservation and to discourage waste. The Committee believes that prompt regulatory response in this area is essential and will be attained.

Deliberately restricting demand or usage. Slowing the rate of growth in electric power loads would help reduce the industry's demands for capital. Under emergency conditions, it may be necessary to develop and apply federal programs for strict conservation and even allocation of energy, as discussed

[16] For about 18 years, Citizens Utilities Company has been using an optional stock dividend plan under a tax ruling which antedates present legal restrictions.

in Chapter II. If such contingencies arise, the electric power industry must cooperate fully. However, it appears certain that, short of dramatic changes in life style and patterns of industrial use, the nation will continue to require abundant energy supplies. Further, it appears that certain forms of energy (such as oil) now heavily relied upon by the nation are in seriously short supply. The Committee believes, therefore, that sharply limiting electricity usage without considering the effects on usage of oil and natural gas would be short-sighted and not in the public interest. In terms of energy equivalents, the U.S. has far more energy reserves in the form of uranium, thorium, oil shale and coal than in the form of crude oil and gas.[17] Central electric power with its ability to utilize such relatively plentiful energy resources in an environmentally acceptable manner, should be relied upon to provide a substantial portion of the nation's energy supplies.

Penalty rates or taxes.—Some people have suggested penalty rates or taxes on usage as a mechanism to discourage wasteful uses of electricity. It is beyond the scope of this report to speculate on the effectiveness of these devices to accomplish such an objective. However useful such measures may be for purposes of conservation and other public purposes, excise taxes or rates designed expressly to reduce electric usage (rather than to reflect costs) are not likely to provide a solution to the financial problems of the electric power industry and, in fact, may magnify them. These problems are related principally to the level of peak demand and associated capacity requirements—not principally to total kilowatthour output. Depending upon their application, penalty rates or taxes might have a greater effect upon usage than upon peak demand. In such a case, capital requirements would not be reduced proportionately, but revenues available to pay for such requirements would be reduced as a result of curtailed consumption. The Committee believes that pricing based on costs—measured and allocated as closely as possible—is the best way to allocate resources.

Exhibit D

Chapter I. Financial Needs of the Electric Power Industry

A. PLANT INVESTMENT AND CONSTRUCTION EXPENDITURES

At December 31, 1974, the U.S. electric power industry will have approximately $150 billion invested in electric utility plant and equipment—generating stations; dams and spillways; transformers, switching and regulating equipment; transmission and distribution towers, poles, lines and hardware; underground vaults and conduit; cooling ponds and towers, and spray canals; pumped storage reservoirs and tractors; radio towers and communications equipment; computers; office buildings and machine shops; nuclear fuel storage facilities; oil storage tanks, coal washers, dryers and handling facilities; freight trains, mines and barges. The electric power industry has the largest plant investment of any U.S. industry and is also the most capital-intensive, with the highest plant investment per dollar of annual sales, as shown below.

TABLE 1.—*Plant investment per dollar of annual sales,[1] Dec. 31, 1973*

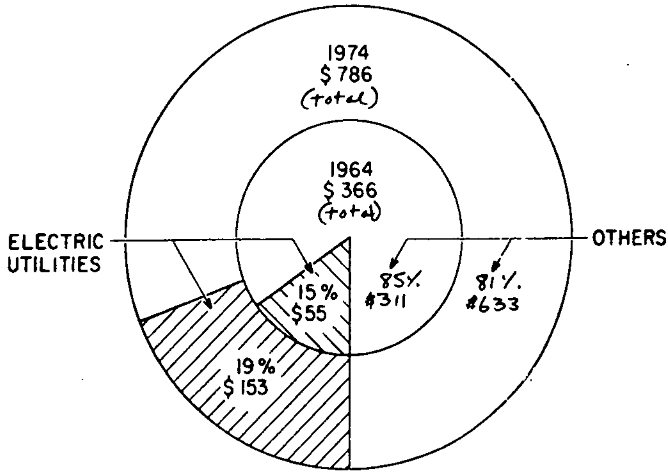
Electric power	$4.25
Telephone	2.83
Railroads	2.67
Gas	2.00
Steel	1.08
Oil	.73
Automobiles	.67

[1] Represents the net book value of investment in business plant and equipment after deducting depreciation reserves, at Dec. 31, 1973, divided by total sales or operating revenues for the year 1973.

Source: EEI Questions and Answers.

[17] Expressed in Q's (Q=a quintillion British Thermal Units), the U.S. has recoverable reserves of oil and gas equivalent to 1 or 2 Q's; of coal equivalent to at least 30 Q's; and of uranium, equivalent to 1000 Q's recoverable at $100 a pound when utilized in a breeder reactor. Moreover, uranium and thorium recoverable from sea water will provide over 200,000 Q's—again when utilized in breeders. Uranium reserves economically usable in light water reactors are considerably smaller.

FIG. A
COMMERCIAL, INDUSTRIAL, UTILITY, & RAILROAD
PLANT INVESTMENT - IN BILLIONS



SOURCE: EEI STATISTICAL YEARBOOK, STATISTICAL ABSTRACT OF THE U.S.

Rising expenditures.—During the 1950's and early 1960's, the construction expenditures of electric power firms remained almost level, but they have nearly quadrupled since then, as shown in Table 2.

TABLE 2.—*U.S. electric power industry construction expenditures,[1] 1950–74*

	Billions
1950–4	$17.8
1955–9	21.7
1960–4	23.0
1965–9	39.8
1970–4 [1]	83.0

[1] Includes net increases in nuclear fuel stocks and allowances for funds used during construction; not reduced by retirements.

Source: Electrical World, "Statistical Reports."

These construction expenditures are expected to continue to rise due to construction cost escalation, environmental requirements and growth in the demand for electric power. Even if growth moderates somewhat, the two other factors will tend to raise future expenditures.

Expenditure projections.—Eight different projections of construction expenditures for the next 15 years have been made in this study, based upon eight degrees of low, intermediate and high growth, combined with different assumed construction cost escalation and environmental protection requirements. The eight combinations of assumptions are summarized briefly in table 3.

TABLE 3.—BRIEF COMPARISON OF CASES, 1975–89

Variables	Cases I, and IA, moderate growth	Case II, historic growth	Case III, low growth	Case IV, all-electric	Case, V "zero" growth	Case VI, topping-out	Case VII, modified topping-out
Annual growth in peak period usage.	Moderately high (5½–6½%).	High (6.6–7.2%).	Low (3–5%).	Very high (8–10%).	Very low (1%).	Quite low (1–6%).	Moderately low (2–4%).
Construction cost Escalation.	High	High	Low	High	Low	Low	Low.
Environmental protection costs.	High (case I), Low (case IA).	Low	High	Low	High	High	High.

Ranges in annual growth rates shown in Table 3 are for the 1976–90 period. Construction cost escalation assumed was roughly 7½% a year to 1980 and thereafter 5% for the high assumptions and 3% for the low. High environmental protection cost estimates were based in part on input assumptions provided by Natonal Economic Research Associates. Low environmental cost estimates were based in part on input assumptions provided by the U.S. Environmental Protection Agency.[1]

The important input assumptions for the seven cases are listed in Exhibits I and II at the close of this chapter. The financial model itself is described in detail in Appendix A.

Projected construction expenditures for each of these cases are set forth as below. All figures include the cost of replacing worn out plant and reflect the anticipated effect of future inflation.

TABLE 4.—U.S. ELECTRIC POWER INDUSTRY CONSTRUCTION EXPENDITURES,[1] 1970–89

[In billions]

	Case I, moderate (high environmental)	Case IA, moderate (low environmental)	Case II, historic	Case III, low growth	Case IV, all-electric	Case V, zero growth	Case VI, topping-out	Case VII, modified topping-out
1970–74[2]	$83	$83	$83	$83	$83	$83	$83	$83
Future:								
1975–79	134	116	129	90	163	32	110	71
1980–84	218	206	246	121	403	37	96	89
1985–89	348	331	439	140	769	40	66	94
Entire period 1975–89	700	653	814	351	1,335	109	272	254

[1] Includes nuclear fuel and allowance for funds used during construction; not reduced by retirements. All expenditures reflect the effect of future inflation, being expressed in "future dollars"—see glossary.

[2] 1974 estimated.

Sources: Electrical World, "Statistical Reports", 1970 and 1973, for 1970–72 data. Model output data reported in appendices for 1975–89 date.

Table 4 shows that if the moderate growth assumptions of Cases I and IA are realized in the future, the industry will be spending between $65 and $70 billion a year for new plant and equipment during the last half of the 1980's. The amount is 4 times the 1970–4 level of $17 billion a year, 13½ times the 1960–4 level of $5 billion a year, and over 20 times the 1950–4 level of $3

[1] EPA estimates are being revised.

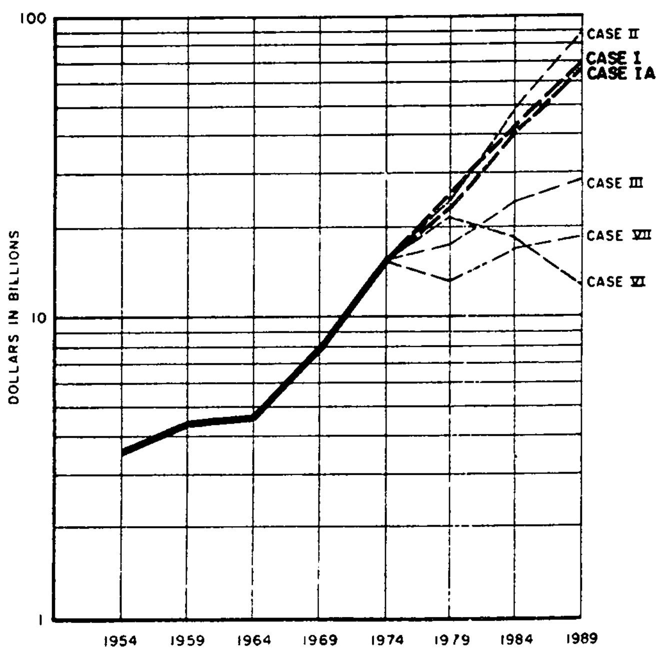
billion annually. Case II which projects load growth at historic rates indicates average annual plant expenditures could reach $88 billion in the 1985–9 period or 5 times present (1970–4) levels. Even under "low growth" case III, electric plant construction expenditures could reach an annual level of nearly $28 billion by 1985–9, with projected expenditures of $32 billion for the year 1990 alone—almost twice the $17 million average for 1970–4.

Cases IV and V, the "all-electric" and "zero growth" cases, respectively, yield results which the Committee feels are unlikely to occur. The "topping-out" concept has considerable appeal. The problem, of course, is to determine when and how fast the future growth in peak period usage may level off.

Comparisons of Past Expenditure Levels with Future Projections.

Figure B shows construction expenditures of the past 25 years, by five-year bands, compared with our projections for the future, excluding the extreme projections of cases IV and V.

FIG. B
U.S. ELECTRIC POWER INDUSTRY
PLANT CONSTRUCTION EXPENDITURES
Annual Averages By Five-Year Periods
1950 - 1989



FOR 5-YEAR PERIODS ENDED WITH YEAR SHOWN
SOURCES: TABLES 2 AND 4

Figure B reveals how dramatic the recent acceleration in construction expenditure growth has been together with our expectations that future growth will moderate somewhat.

During the 25 year period, 1950–74, plant construction expenditures grew at an annual rate of about 8%. However, during the first 15 years of that period, growth averaged only 3% a year, while it has averaged 16% annually since 1965.[2]

Future growth rates are expected to be somewhat lower than for the recent past. Under the "moderate growth" cases I and IA, future plant construction expenditures are expected to grow at annual rate of approximately 10%. Our projections are 12¾% for "historic growth" case II and 5% for "loy growth" cas III.[3] Under the "topping out" assumption (case VI), the growth rate averages 6% a year for the 1976–80 period, 3% a year for the 1981–5 period and 1% thereafter. Under the "modified topping-out" assumption (case VII), the growth rate averages 4% a year for the 1976–80 period, 3% for the 1981–5 period and 2% thereafter. An important characteristic of the operation of the model is that growth rate assumptions subsequent to 1985 carry on for more than ten years, until 1995 or later, because long construction lead times necessarily mean that plans for meeting loads in the 1990's will have important effects upon expenditures in the late 1980's.

Preferred projections

Figure B also makes clear the wide array of possibilities which the future holds, especially if sales growth should gradually level off in the 1980's, as assumed in the "topping out" case. While the Committee believes the "moderate" projection (case IA) represent the more likely possibility, it is pointed out elsewhere that recent *Electrical World* projections, escalated to 1980 dollars, fall somewhere between the moderate (case IA) and modified topping-out (case VIII) projections for the early 1980's.[4]

Financing requirements

During the early 1960's, the electric power industry was able to finance most of its $5 billion average annual construction expenditures with internally generated funds provided mainly from depreciation and deferred tax accruals and retained earnings. Outside financing needs then averaged less than $2 billion annually. By the early 1970's, however, such external needs had grown to over $10 billion a year,[5] because the increases in internal cash generation had not kept pace with the rise in expenditures.

The relevant data for the last 25-years are shown in Table 5.

TABLE 5.—U.S. ELECTRIC POWER INDUSTRY SOURCES OF CONSTRUCTION FINANCING, 1950–74
[Dollars in millions]

		Construction funds provided by—		Percent of construction funds provided by—	
	Construction expenditures [1]	Funds generated internally [2]	External financing [3]	Funds generated internally [2]	External financing [3]
1950–4	$17.8	$7.2	$10.6	40.4	59.6
1955–9	21.7	9.7	12.0	44.7	55.3
1960–4	23.0	13.6	9.4	59.1	40.9
1965–9	39.8	19.8	20.0	49.7	50.3
1970–4 [4]	83.0	30.0	53.0	36.1	63.9

[1] Includes net increases in nuclear fuel stocks and allowances for funds used during construction; not reduced by retirements.
[2] See Glossary definition of "internal cash generation." Excludes funds used for non-construction cash requirements. Figures for the 1950–4 period have been increased by $1.9 billion to balance.
[3] Excludes refundings.
[4] 1973 and 1974 estimated.

Note.—Similar projections for the future are set forth in Table 6 and shown graphically in Figures C and D.

Sources: Electrical World, "Statistical Reports" 1959, 1966 and 1974 and EBASCO Business and Economic Charts, 1970 and 1973.

[2] All annual growth rates referred to in the following paragraphs are based upon least squares trend lines applied to annual data.
[3] "Low growth" expenditures growth is 12½% a year for the 1975–79 period, because much construction work for these years is already committed for, but only 1½% a year thereafter.
[4] See Table 8.
[5] Exclusive of security refundings.

TABLE 6.—U.S. ELECTRIC POWER INDUSTRY SOURCES OF CONSTRUCTION FINANCING,[1] 1970–89

[In billions]

	Case I, moderate (high environmental)	Case IA, moderate (low environmental)	Case II, historic growth	Case III, low growth	Case IV, all-electric	Case V, zero growth	Case VI, topping out	Case VII, modified topping-out
Funds generated internally:[2]								
1970–74[3]	$30	$30	$30	$30	$30	$30	$30	$30
1975–79	51	46	51	43	56	34	47	41
1980–84	86	80	90	62	121	38	63	53
1985–89	143	134	164	83	254	42	71	66
Total—A (1975–89)	280	260	305	188	431	114	181	160
Percent of Grand total	40	39.8	37.5	53.6	32.3	100	66.5	63
External financing:[4]								
1970–74[3]	$53	$53	$53	$53	$53	$53	$53	$53
1975–79	83	70	78	47	107	(2)	63	30
1980–84	132	126	156	59	282	(1)	33	36
1985–89	205	197	275	57	515	(2)	(5)	28
Total—B (1975–89)	420	393	509	163	904	(5)	91	94
Percent of Grand total	60	602	62.5	46.4	67.7	----------	33.5	37
Grand total (A plus B) (1975–89)	$700	$653	$814	$351	$1,335	$109	$272	$254

[1] All future estimates are expressed in "future dollars" (see Glossary) reflecting anticipated future inflation.
[2] See glossary definition of "internal cash generation." Excludes funds used for nonconstruction cash requirements.
[3] 1973 and 1974 estimated.
[4] Excludes refundings. The amount of future refundings will depend upon the maturities of existing and future debt issues. Approximately 16 billion of funded debt now outstanding is scheduled to mature before 1990.

Possibility of improvement in future outlook

Although Figure D shows that future external financing requirements are likely to increase somewhat, the rate of increase may be less than in the recent past. This is because the percentage of construction funds provided internally is expected to improve. See Figure E.

The early 1960's are often thought of as a period when more construction funds were provided internally than today. However, the dollar amount of such internal provisions is much higher today than it was during the early 1960's. Although the proportion of construction funds provided internally declined from 60% in the early 1960's to a low of 30% by the early 1970's, there was a marked improvement in 1973, when internal sources provided about 40% of the construction funds. This improvement may not have been the beginning of a trend, but the outlook for a definite turn-around by the late 1970's is favorable. All of which indicates that, within a few years, the industry should, with adequate rates and diligent management, be able to cope successfully with what today appears a straggering financing problem, provided that tax changes and other measures needed to stimulate internal cash generation are adopted as discussed below.

Possible changes in tax and accounting policy

Such changes can have important effects upon future cash needs. Figure F[5a] shows how five tax and accounting changes would affect the proportion of funds provided internally under case I. These five changes are:

(i) To increase book depreciation rates to 5%.

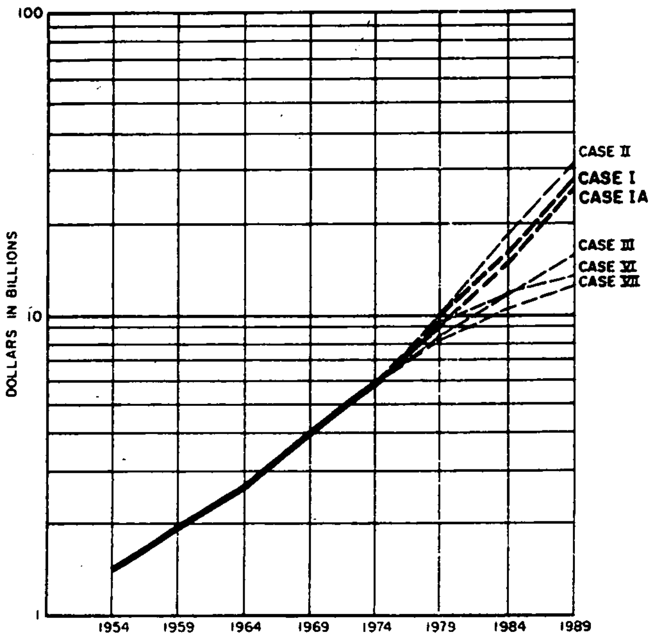
[5a] See Fig. F, p. 130.

FIG. C

U.S. ELECTRIC POWER INDUSTRY FUNDS GENERATED INTERNALLY

Annual Averages By Five-Year Periods

1950 - 1989



FOR 5 YEAR PERIODS ENDED WITH YEARS SHOWN

SOURCES TABLES 5 AND 6

(ii) To "normalize" all tax deferrals; i.e. to make appropriate charges to income and credits to deferred credit accounts for all taxes deferred by accelerated depreciation, the investment tax credit, guideline tax lives, and the like;[6]

(iii) To shorten all tax and book depreciation lives to 20 years;

(iv) To increase the investment tax credit to 7% (with concommitant relaxation of the rules restricting the use of such credits);

(v) To allow the tax-free reinvestment of 40% of cash dividends in new-issue common stock.[7]

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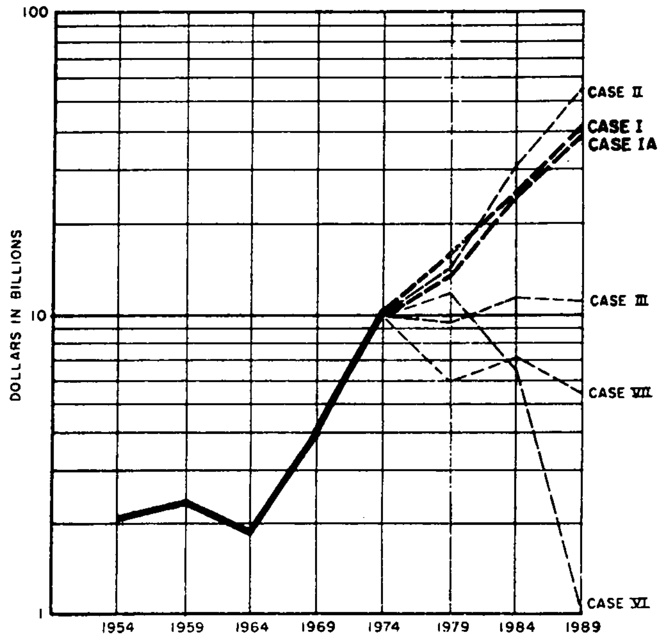
[6] See Glossary for a more complete definition of "normalization."

[7] A rough estimate of the dividend reinvestment which might be induced by changes in the Internal Revenue Code exempting such reinvested dividends from federal tax or permitting the tax-free receipt of optional stock dividends in lieu of cash. See recommendation number six in the Introduction and Summary.

FIG. D
U.S. ELECTRIC POWER INDUSTRY
NET EXTERNAL FINANCING
Annual Averages By Five-Year Periods
1950-1989



FOR 5-YEAR PERIODS ENDED WITH YEAR SHOWN.
SOURCES: TABLES 5 & 6.

Figure F, illustrated on page 130, demonstrates the importance of such tar and financing measures needed to maximize internal cash generation.

Preferred projections

The projections herein are not presented as a blueprint for the future. The majority of the Committee is inclined toward Case IA, but there are many possible variations of even these cases—also many different views exist among individuals of our Committee as to preferable tax and fiscal policies. Consequently, we have not attempted to superimpose our own preferred targets upon the various arrays of projection lines which fan out in the future. Even as to the possibility of future increases in internal cash generation, we are not of a single mind, but we all agree that the amount of funds provided internally should be maximized.

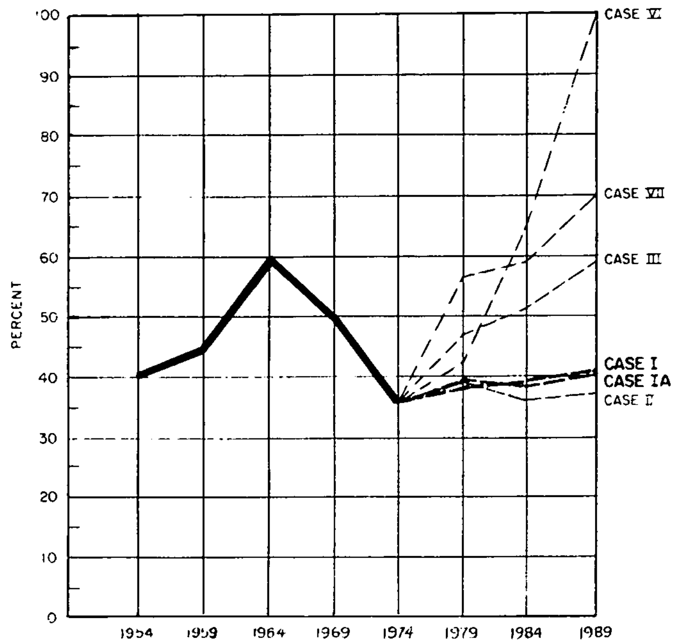
Effect of varying the assumptions.—Changes in the three key variables, especially future growth rates, could have dramatic effects upon future financing requirements. For example, under "moderate growth" case I, the projected 15-year external financing requirements are $420 billion. However, if the "low" rate of growth were assumed, the figure would be 49% lower or $215 billion. If the "low" rate of construction cost escalation were also assumed, these new money needs would be reduced another 24% to $163 billion.

Fig. E

U.S. ELECTRIC POWER INDUSTRY FUNDS PROVIDED INTERNALLY AS A PERCENTAGE OF TOTAL FINANCING REQUIREMENTS

Averages for Five-Year Periods

1950 - 1989



FOR 5-YEAR PERIODS ENDED WITH YEAR SHOWN

SOURCES: TABLES 5 AND 6

If electricity usage and construction expenditures taper off in the 1980's (as predicted by case VII), 15-year new money needs will be only $94 billion.

A wide range of estimates has been prepared by varying different input assumptions for the moderate growth case A. These are tabulated in Exhibit 3 at the end of this chapter and described in full in Appendix A.

C. COMMENTS ON INFLATION

It is important to recognize that none of the wide array of future possibilities we have projected assumes run-away inflation or even an unusually high rate of general price level inflation. In keeping with the basic ground rules for the National Power Survey, we have assumed inflation rates as measured by the GNP price deflator in the 3 to 5% annual, range.[8] Should inflation remain at an annual level of 10% or more, the industry's financing problems would be significantly increased. Individual savings would be discouraged by the expectation of continued high inflation and, under conventional regulatory procedures, it would be difficult to raise elertricity rates fast enough to cope

[8] Our assumption as to higher rates of construction cost escalation during the remainder of the 1970's reflect cost requirements in addition to those imposed by general inflation.

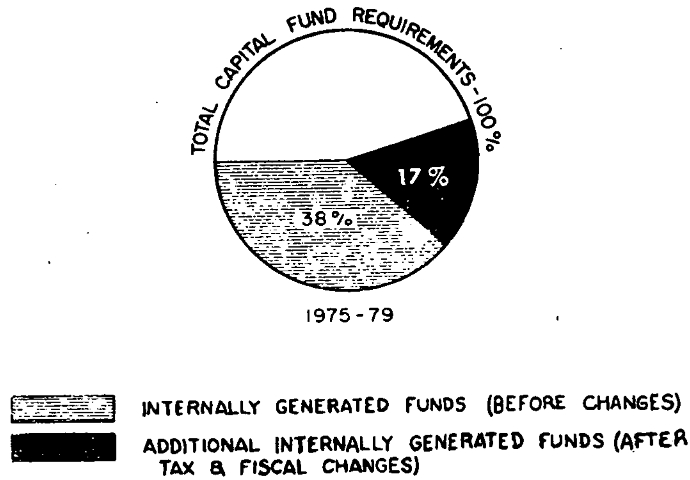


FIGURE F

U.S. ELECTRIC POWER INDUSTRY FUNDS PROVIDED INTERNALLY AS A PERCENTAGE OF TOTAL CAPITAL FUND REQUIREMENTS – ASSUMING CERTAIN CHANGES IN TAX & FISCAL POLICY

FIVE YEAR PERIOD 1975-1979

with run-away inflation. This suggests that the continuation or acceleration of excessive inflation in this country is likely to result in significant financial difficulties for the electric power industry, both public and private.

D. RELATIONSHIP OF FUTURE ELECTRIC POWER FINANCINGS TO THE SIZE AND FINANCING NEEDS OF THE ECONOMY AS A WHOLE

Between 1950 and 1970, external financings of the U.S. electric power industry, excluding refundings, averaged about one-half of one percent of Gross National Product. By the early 1970's the figure had reached one percent. Although it may go somewhat higher in the future, Table 7 indicates a distinct possibility that future increases can be held to a minimum, at least under cases I and IA.

TABLE 7.—U.S. ELECTRIC POWER INDUSTRY ESTIMATED EXTERNAL FINANCING, EXPRESSED AS A PERCENTAGE OF GROSS NATIONAL PRODUCT [1], ANNUAL AVERAGES BY 5-YEAR PERIODS

	Amount of Gross National Product (trillions)		Percent							
	High estimate [1 2]	Low estimate [2]	Case I	Case IA	Case II	Case III	Case IV	Case V	Case VI	Case VII
1960-4 (actual)	$0.6	$0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
1965-9 (actual)	.8	.8	.5	.5	.5	.5	.5	.5	.5	.5
1970-4 [3]	1.2	1.2	.9	.9	.9	.9	.9	.9	.9	.9
1975-9	1.8	1.8	.9	.8	.9	.5	1.2		.7	.3
1980-4	2.7	2.5	1.0	.9	1.2	.4	2.1		.2	.3
1985-9	4.0	3.4	1.0	1.0	1.4	.3	2.6			.1

[1] Based on external financing figures shown in tables 5 and 6, excluding refundings.
[2] The "high" GNP estimate assumes general price inflation of 5 percent per year for the 1975-89, which is consistent with cases I, IA, II, and IV, while the "low" GNP estimate assumes 5 percent annual inflation for 1975 to 1979 and 3 percent for 1980-89, thus being consistent with cases III, V, VI, and VII.
[3] 1973 and 1974 data estimated.

These projections indicate that the nation's economy is certainly capable of financing an expanded electric power industry. They suggest, however, that some shift in priorities must occur if electric power is to provide an increasing share of the nation's energy needs—a course that the Committee regards as consistent with attainment of the widely articulated goal of energy self-sufficiency as well as the maintenance of high environmental standards. Therefore, the electric industry's securities must be made more attractive to investors than they now are through more efficient utility management and greater regulatory responsiveness, or the money to do the job simply will not be available short of government subsidy.

E. RELATIONSHIP TO OTHER FINANCIAL FORECASTS

There have been a number of other forecasts of the future financial requirements of the electric power industry. With one exception, referred to below, such other forecasts are roughly consistent with our projections. After masing adjustments necessary to assure comparability with ours, construction expenditures five years hence (i.e. 1979–1980) indicated in those other forecasts tend to approximate our "moderate" and "historic" growth estimates of cases I and II. This is shown in Table 8.

TABLE 8.—COMPARISON TO OTHER FORECASTS: A STATEMENT SHOWING VARIOUS ESTIMATES OF ELECTRIC PLANT CONSTRUCTION EXPENDITURES FOR THE ENTIRE U.S. ELECTRIC POWER INDUSTRY

		1980		
	Basis	Estimates reported in other forecasts	Adjusted where necessary to include public and cooperative sectors	Further adjusted to 1980 [1] dollars
1970 National Power survey [2]	1970 dollars	$20.0	$20.0	$41.0
Mishara (1973) [3]	1972 dollars	20.6	[4] 25.8	44.9
Symonds (1973) [5]	1970 dollars	20.6	[4] 25.8	52.9
1973 Electrical World [6]	1973 dollars	25.1	25.1	40.4
1974 Electrical World [7]	1974 dollars	19.5	19.5	28.9
Haas, Mitchell, Stone [8]	1970 dollars	26.8	26.8	54.9
Our projections:				
Case I	1980 dollars			36.1
Case IA	do			32.3
Case II	do			36.6
Case III	do			22.2
Case VII	do			17.1

[1] Adjustments to 1980 dollars were based upon a rough average of construction cost escalation rates assumed in our forecasts—9% annually from 1970 to 1975 and 6.5% annually thereafter. See exhibits 1 and 2 at the close of this chapter.
[2] Federal Power Commission, John Nassikas, Chairman, "1970 National Power Survey."
[3] Donald Mishara, "Future Financing and Capital Requirements," June 12, 1973. (Mr. Mishara is vice president of Smith, Barney & Co.)
[4] Basic figure increased by 25%.
[5] Edward Symonds, "hearings on Financial Requirements of the U.S. Energy Industries," Mar. 6, 1973. (Mr. Symonds is vice president of Petroleum Department, First National City Bank, New York, N.Y.)
[6] Electrical World, "24th Annual Electrical Industry Forecast," Sept. 15, 1973.
[7] Electrical World, "25th Annual Electrical Industry Forecast," Sept. 15, 1974.
[8] Jerome Haas, Edward Mitchell and Bernell Stone, "Financing and Energy Industry," 1974. A report to the energy policy project of the Ford Foundation.

Exception

On September 15, 1974, *Electrical World* reduced its long-range projections below earlier forecasts. As shown in Table 9, its projections of output, peak loads and generating capability track our Cast I until the early 1980's. Thereafter, the new Electrical World projections of output and capacity needs taper off. As a result, its estimates of 1980 construction expenditures (in anticipation of later capacity needs) are only $29 billion expressed in 1980 dolltrs. These are well below our Case I and IA estimates of $36.1 and $32.3 billion respectively but higher than cases III and VII, "low" and "modified topping-out" growth respectively.

F. RELATED PROJECTIONS OF OUTPUT, LOAD AND GENERATING CAPACITY

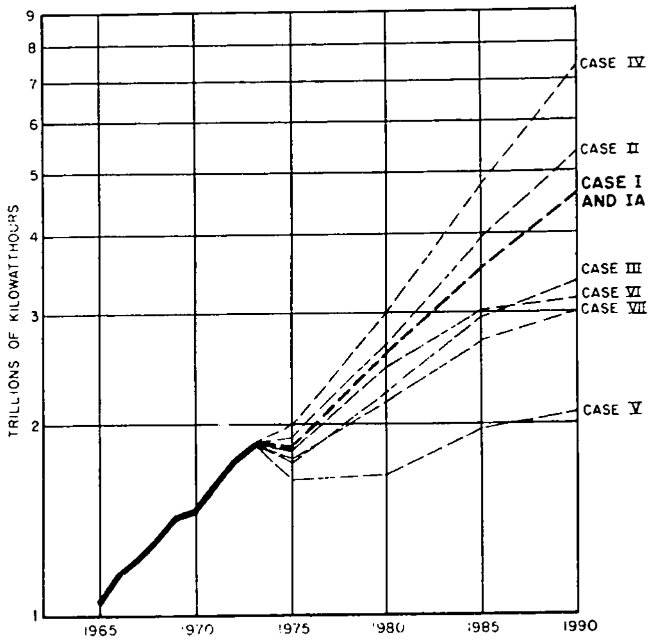
The foregoing financial projections were based upon the following estimates of electrical output, peak loads and generating capacities for the industry as a whole, as shown in Table 9.

TABLE 9.—U.S. ELECTRIC POWER INDUSTRY ELECTRICAL OUTPUT, LOADS, AND CAPACITIES,[1] 1970–90

	Cases I and IA, moderate growth	Case II, historic growth	Case III, low growth	Case IV, all-electric	Case V, zero growth	Case VI, topping out	Case VII, modified topping out	For comparison: Electrical World's 25th forecast[2]	For comparison: TAC-power supply projections "most probable case"[3]
Electrical output (trillions of kilowatt hours):									
1970 (actual)	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	----------
1975	1.83	1.92	1.91	2.00	1.72	1.86	1.81	2.06	----------
1980	2.62	2.77	2.36	3.00	1.79	2.56	2.19	2.77	3.20
1985	3.55	3.91	2.95	4.83	1.96	3.01	2.71	3.59	4.40
1990	4.64	5.38	3.42	7.40	2.09	3.16	2.99	4.64	5.80
Peak loads (millions of kilowatts):									
1970 (actual)	275	275	275	275	275	275	275	275	----------
1975	370	380	362	388	352	370	366	387	----------
1980	506	539	462	570	370	494	445	514	584
1985	677	745	563	917	389	573	516	661	819
1990	885	1,025	652	1,411	408	602	570	849	1,076
Total generating capacity (millions of kilowatts):									
1970 (actual)	328	328	328	328	328	328	328	328	----------
1975	466	487	471	481	464	473	476	494	----------
1980	623	668	583	678	495	608	541	624	----------
1985	813	894	675	1,092	497	688	619	781	----------
1990	1,062	1,230	783	1,694	511	723	684	1,003	----------

[1] Excludes nonutility private powerplant generation. The values shown in this table are given historical perspective in figs. G, H, and I.
[2] "Electrical World," Sept. 15, 1974.
[3] Report to the Federal Power Commission by the NPS–TAC on power supply.

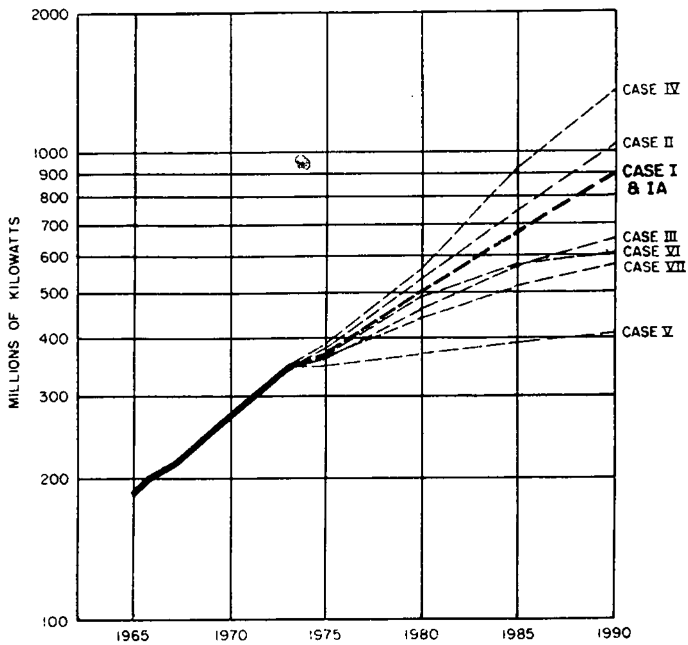
Fig. 6
U.S. ELECTRIC POWER INDUSTRY
ELECTRICAL OUTPUT
1965-1990



SOURCE: TABLE 9

~~Fig. 11~~

U. S. ELECTRIC POWER INDUSTRY
ELECTRICAL PEAK LOADS
1965 - 1990

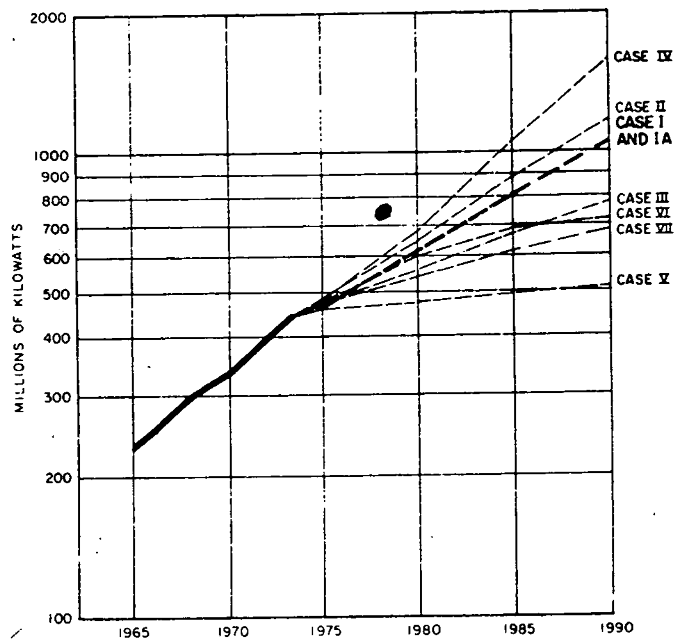


SOURCE: TABLE 9

FIG. I

U.S. ELECTRIC POWER INDUSTRY GENERATING CAPACITY

1965 - 1990



SOURCE: TABLE 9

Exhibit I

Construction costs assumed for electric utility plant facilities completed and placed in service during the year 1970 (these cost assumptions are common to all scenarios.)

	Per kilowatt
Base-load generation:	
Fossil	$120
Nuclear	150
Peaking capacity (gas turbines, diesels, fast-startup or cycling coal, etc.)	90
Nuclear fuel	38
Transmission and distribution plant additions (per kilowatt of added system peak load)	180

NOTE.—See app. A for additional cost assumptions common to all scenarios.

These 1970 investment cost estimates have been escalated to 1972 (the "base period" in our model) on the same basis for all cases and thereafter at various rates for various cases, as set froth in Exhibit II. They thus provide the basis for deriving the unit cost estimates at which new plant will be brought on line in future years.

Key Variable Assumptions.—The assumed growth rates, varying escalation rates and environmental fix-up costs, representing the three key categories of assumptions which vary among cases, are set forth in Exhibit II.

EXHIBIT II

3 KEY CATEGORIES OF VARIABLE ASSUMPTIONS [1]

	Estimated annual percentage rates						
	1970–72 [2]	1973	1974	1975	1976–80	1981–85	1986–90 (and subsequent years)
Rates of growth in peak load demand:							
I. Moderate			1.0	4.0	6.5	6.0	5.5
II. Historic			3.0	5.0	7.2	6.7	6.6
III. Low	7.4	9.4	0	3.0	5.0	5.0	3.0
IV. All-electric			3.0	7.0	8.0	10.0	9.0
V. Zero growth			0	0	1.0	1.0	1.0
VI. Topping-out			1.0	4.0	6.0	3.0	1.0
VII. Modified topping-out			1.0	3.0	4.0	3.0	2.0
Construction cost escalation rates:							
Fossil fuel generating plant construction costs (both base-load and peaking):							
High	[3] 11.2	11.2	11.2	11.2	7.46	5.0	5.0
Low	[3] 11.2	11.2	11.2	11.2	7.46	3.0	3.0
Nuclear generating plant construction costs:							
High	14.7	14.7	14.7	14.7	7.6	5.0	5.0
Low	14.7	14.7	14.7	14.7	7.6	3.0	3.0
Nuclear fuel investment costs:							
High	5.0	3.0	3.0	3.0	3.0	6.0	6.0
Low	5.0	2.0	2.0	2.0	2.0	4.0	4.0
Transmission and distribution plant construction costs:							
High	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Low	5.0	5.0	5.0	5.0	5.0	3.0	3.0
Environmental protection costs: [4]							
Cooling towers or other closed-cycle cooling (fossil):							
New:							
High	8.12	5.7	5.7	5.7	5.7	5.0	5.0
Low	4.89	5.7	5.7	5.7	5.7	3.0	3.0
Retrofit:							
High	23.16	5.7	5.7	5.7	5.7	5.0	5.0
Low	20.43	5.7	5.7	5.7	5.7	3.0	3.0
Cooling towers or other closed-cycle cooling (nuclear):							
New:							
High	5.89	5.8	5.8	5.8	5.8	5.0	5.0
Low	3.84	5.8	5.8	5.8	5.8	3.0	3.0
Retrofit:							
High	27.88	5.8	5.8	5.8	5.8	5.0	5.0
Low	24.58	5.8	5.8	5.8	5.8	3.0	3.0
Stack gas desulfurization (fossil):							
New:							
High	80.00	5.7	5.7	5.7	5.7	5.0	5.0
Low	30.00	5.7	5.7	5.7	5.7	3.0	3.0
Retrofit:							
High	100.00	5.7	5.7	5.7	5.7	5.0	5.0
Low	40.00	5.7	5.7	5.7	5.7	3.0	3.0

[1] Some of the figures set forth herein have been rounded for simplicity. Growth rates shown are for the year or years indicated compared with the next preceding year.
[2] Assumptions for the 1970–72 period are the same for all 8 cases.
[3] Peaking capacity costs are assumed to have escalated $10 per kilowatt from 1970 to 1972.
[4] In addition to the costs per kilowatt and escalation rates set forth above, the assumptions as to the proportion of generating capacity requiring environmental fixup were varied among cases as shown on p. 3 of this exhibit.

	1972 value per kilowatt
Chemical effluent control cost—	
To meet 1977 guidelines:	
1970 capacity:	
High	$0
Low	0.58
1971–77 capacity:	
High	0
Low	.58
To meet 1983 guidelines:	
1970 capacity:	
High	0
Low	0
1971–77 capacity:	
High	0
Low	0
1978–90 capacity:	
High	0
Low	.48
Chemical effluent control operating cost:	
To meet 1977 guidelines:	
1970 capacity:	
High	0
Low	.20
1971–77 capacity:	
High	0
Low	.20
To meet 1983 guidelines:	
1970 capacity:	
High	0
Low	0
1971–77 capacity:	
High	0
Low	0
1978–90 capacity:	
High	0
Low	.20

ESTIMATED PROPORTIONS OF GENERATING FACILITIES REQUIRING ENVIRONMENTAL FIXUP

	Service dates of related generating facilities	Estimated proportion requiring fixup (percent)	
		High	Low
Cooling towers or other closed-cycle cooling:			
Nuclear	1973 and before	46	13
	1974–78	100	78
	1979–90	100	72
Fossil	1973 and before	4	3
	1974–78	100	75
	1979–90	100	77
Stack gas desulfurization (fossil only)	1975 and before	33	[1]
	After 1975	50	33
Chemical effluent control:			
Nuclear	All	100	100
Fossil	1973 and before	100	100
	1974–78	100	100
	1979–90	100	100

[1] 60,000 MW.

Comments on the foregoing tabulations

(i) As to load growth assumptions, the case titles are fairly descriptive—"moderate," "historic," "topping out" etc., The patterns selected reflect varying attitudes expressed by Committee members.

(ii) As to construction cost escalation, a degree of moderation has been assumed for the late 1970's and especially for the decade of the 1980's—perhaps with undue optimism. In general, the earlier years are assumed to continue to reflect a composite of general cost inflation and increasing "real costs" resulting, for example, from the imposition of OSHA (safety) and licensing requirements.

Near-term future cost trends for generating capacity were developed by applying straight-line regression curves to specific estimates collected from the industry at large.

(iii) As to environmental expenditures, the wide range of base-year assumptions reflect a considerable variation of opinion among members of the Committee.

EXHIBIT III

SENSITIVITY ANALYSES, 1975-89, PROJECTED CONSTRUCTION EXPENDITURES AND EXTERNAL FINANCING REQUIREMENTS

[In billions of current dollars]

	Construction expenditures				External financing			
	1975-79	1980-84	1985-89	Total	1975-79	1980-84	1985-89	Total
Case No. 1A (baseline)	$116	$206	$331	$653	$70	$126	$197	$393
With lower inflation	115	181	291	587	69	113	162	344
Without pollution control	109	200	326	635	64	121	193	378
Without thermal	114	205	329	648	68	125	196	389
Without chemical	115	205	331	651	69	125	197	391
Without air	111	202	328	641	66	122	195	383
With reduced reserve margins	112	214	339	665	67	132	203	402
With increase in depreciation rate	116	206	331	653	55	105	163	323
With elimination of asset depreciation range	116	206	331	653	71	127	198	396
With elimination of investment tax credit	116	206	331	653	71	127	199	397
With increase in investment tax credit to 7 percent	116	206	331	653	69	125	195	389
With increase in investment tax credit to 10 percent	116	206	331	653	68	124	194	386
With increase in nuclear generation in 1980's	117	214	349	680	71	133	209	413
With 12 percent allowed rate of return	116	206	331	653	70	127	200	397
With increase in interest rate	116	206	331	653	70	126	197	393
With decrease in dividend payout	116	206	331	653	63	115	179	357
With change in capital structure	116	206	331	653	69	124	193	386
With switch to normalized accounting	116	206	331	653	62	110	169	341
With switch to flow-through accounting	116	206	331	653	73	133	207	413

Note.—Preliminary, subject to revision.

EXHIBIT E

FEDERAL POWER COMMISSION, NATIONAL POWER SURVEY

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Mr. D. E. Albertson, Public Utilities Management Division, General Services Administration, Crystal Mall 4, Washington, D.C. 20406.

Mr. David H. Askegaard, Assistant Administrator, Electric Rural Electrification Administration, U.S. Department of Agriculture, Washington, D.C. 20250.

Mr. Hugh A. Barker, President, Public Service Company of Indiana, Inc., 1000 E. Main Street, Plainfield, Indiana 46168.

Mr. Jack F. Bennet, Deputy Under Secretary for Monetary, Affairs, Department of the Treasury, 15th & Pennsylvania Avenue, N.W., Washington, D.C. 20220.

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Mr. Paul Fry, Staff Economist, American Public Power Association, 2600 Virginia Avenue, N.W., Washington, D.C. 20037.

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Mr. Edwin L. Kennedy, Managing Director, Lehman Brothers, Inc., One William Street, New York, New York 10004.

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Mr. T. M. McDaniel, Jr., President, Southern California Edison Company, 2244 Walnut Grove Avenue, Rosemead, California 91770.

Mr. John R. O'Connor, Staff Advisor, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Mr. Barrett J. Riordan, Council on Environmental Quality, 722 Jackson Place, Washington, D.C. 20006.

Mr. Charles H. Whitmore, President & Chairman of the Board, Iowa-Illinois Gas & Electric Company, 206 E. Second Street, Davenport, Iowa 52808.

Mr. John G. Winger, Vice President, Energy Economics Division, Chase Manhattan Plaza, New York, New York 10015.

Mr. Alan M. Wright, Administrator, Financial Models, Southern Services, Inc., Perimeter Center East, P.O. Box 720071, Atlanta, Georgia 30346.

EXHIBIT F

Unit	Type	Scheduled service date	Net capability (kilowatts)	[1] Estimated cost per kilowatt
Powerton 6	Coal	1975	840,000	$229
Collins 3	Oil	1977	500,000	
Collins 2	Oil	1977	500,000	
Collins 1	Oil	1978	500,000	262
Collins 4	Oil [2]	1978	500,000	
Collins 5	Oil [2]	1979	500,000	
LaSalle County 1	Nuclear	1978	1,078,000	364
LaSalle County 2	do	1979	1,078,000	
Byron 1	do	1980	1,120,000	450
Byron 2	do	1982	1,120,000	
Braidwood 1	do	1981	1,120,000	446
Braidwood 2	do	1982	1,120,000	
Carroll County 1 [3]	do	1984	747,000	636
Carroll County 2 [3]	do	1985	747,000	

[1] Cost excludes cooling lake, lake land, and station land where applicable.
[2] Convertible to coal, if necessary.
[3] The net capability and estimated construction cost represent the Company's ⅔ ownership interest in each unit. Iowa-Illinois Gas and Electric Co. and Interstate Power Co. will have a ⅓ combined ownership interest in each unit.

Representative MOORHEAD. Thank you very much, Mr. Corey. Now I would like to hear from Mr. Mackie. Would you summarize your statement, please. The entire statement will be made a part of the record.

STATEMENT OF FREDERICK D. MACKIE, PRESIDENT AND GENERAL MANAGER, MADISON GAS & ELECTRIC CO.

Mr. MACKIE. Thank you. I would like to say, Mr. Moorhead that I appreciate very much the opportunity to be here and testify today, and also appreciate very much your recognition of the problems our industry faces as you spelled them out in your opening statement.

I represent Madison Gas & Electric Co. which is, by comparison with other utilities, a small utility located in Madison, Wis., serving something on the order of 85,000 electric customers and 52,000 gas customers.

Our company's market is atypical in that industrial sales are a substantially lesser percent of total sales than for most electric utilities. I have shown some statistics on this in my prepared statement, which show that only 9.6 percent of sales are industrial sales, whereas most utilities run at 25 or 35 percent industrial sales, which makes our market quite different. This becomes significant when we get into a discussion of rates.

The matter of rate design is certainly complicated and has received a great deal of attention. I couldn't begin to cover it in this brief statement, but I have attached as the last page of my testimony some references which I think bear on this, and which are readily available, including the proceedings of the extensive hearings held before the Federal Energy Administration earlier this year. Also, I have made available to members of the committee a copy of the Wisconsin Public Service Commission order in our most recent rate case, which attracted a great deal of attention and the discussion by the commissioners in that rate case, which I believe was very informative and very instructive in this entire matter.

Now, my prepared testimony, Mr. Chairman, dealt principally with the answers to the six questions which were in your letter, which was directed to me. I might very very, very briefly cover the answers to those.

The first question was: what long-term rate of growth in electricity generating capacity do we anticipate will be necessary to meet future demands for electricity? In my prepared testimony I have shown our statistics for several years, which show that for many years, our demand has grown at the rate of anywhere from 8 to 11 percent and average over the past 9 years, 8.6 percent. In the summer of 1974, it actually was less. It decreased 5.1 percent compared to 1973.

Now, we have tried to very carefully analyze new construction in our service area that we can see coming, and the other factors which we believe will impact upon demand, and we feel that our rate of growth will be something in the order of 6 percent per year in the immediate future.

There are factors which are affecting it downwards and there are factors which are affecting it upwards, and these are spelled out also in my prepared testimony.

Question number two related to the impact of recent energy conservation measures on producing a growth rate that differs significantly from historical standards. Here I have shown figures not only for demand, but for kilowatt hours of consumption per month, which I think show clearly what has happened. The 1973 summer loads did not increase materially over 1972, which was prior to the energy crush. The summer of 1973, however, was significantly cooler than the summer of 1972. I guess we would have to say that it is not possible to determine exactly the impact of each factor that entered into this, that is, weather, conservation, and things like that. But in our judgment, the energy conservation movement certainly accounts for a very substantial portion. I think this is particularly true in a city like Madison, which is the capital of the State, and has significant government institutions, including the University of Wisconsin, which is our biggest customer. When the Governor of the State told all governmental units to, make a substantial cutback, they did. This was clearly evident in our loads.

Question number three was: to what extent can increased implementation of peak-load prices and long-run incremental cost pricing impact on the demand for electricity generating capacity? I guess we would have to say in summary that practically all the experience in this area is confined to England, France, and Germany, where substantially different conditions prevail. Mr. Corey has said we lack experience. At the moment, we are doing research work to try and determine what will happen. But the first thing I think we will see will be the summer of 1975 when we will have our first experience with rates which are higher in the summertime than in the winter. It will be most interesting to see what will happen.

Question number four related to other measures besides peakload pricing we can use to improve the rate of capacity utilization in the electric utility industry. Here we have said that there are several means of improving the load factor other than peak-load pricing, and the most obvious is offpeak pricing. This practice has prevailed for many years with such loads as offpeak water heating, which is one of the better known applications. The advantage of offpeak pricing is that it is not necessary to pinpoint the offpeak period. You have a much broader range of hours of use with offpeak pricing than in trying to predict and pinpoint the onpeak time, which is much harder to do because it is affected by weather conditions that are still harder to predict.

Question No. 5: Do you believe that peakload pricing will have a significant impact on increasing the capacity utilization of generating equipment?

Here again, we are really only at the threshhold of this development and I am not in a position to predict what will happen. I think this picture is further clouded by the uncertainty of the quantities and prices of alternative possible fuels. Under more normal conditions, effective peakload pricing might force some to either use full or supplementary service from other energy sources. Viable alternatives are not available or cost too much. Such customers will be forced to pay the higher increased rates with little or no shift in loads from peak to offpeak.

Question No. 6: What problems have arisen with the implementation of your peakload pricing experiments? Except for the summer and winter differentials, our company has not yet embarked on a full load program of peakload pricing. The August 1974 order of the Wisconsin commission did not prescribe specific peakload pricing rates, but did direct a study. I have also attached to my prepared testimony a copy of our proposal which the commission has not yet accepted, and which probably will be modified by discussions between our company and the commission's staff. Hopefully we will have this well underway before the next summer's peakload conditions arise.

Now, like Mr. Corey, Mr. Chairman, I would like to respond very briefly to the other questions which were raised in the news release, and I will try not to repeat any of the things which he said, but might perhaps elaborate on them just a little bit.

Question No. 1 related to energy conservation efforts. I think that has been adequately answered.

Question No. 2: What is responsible for the slow pace with which the utility industry has adopted peakload pricing and other strategies to improve utilization of equipment? I think there is another important factor here which should be touched on, and that is the availability of equipment to do this kind of thing. There is available to our industry today practically no reasonably priced equipment on a mass-produced basis to meter on a peakload pricing basis. The conventional kilowatt-hour meter, which is a very reliable and highly accurate device, is simply not suitable to measure two different kinds of loads at different times. I had our people prepare a little bit of information for me here, which is summarized as follows:

Our current investment in meters and associated equipment is about $2.5 million and average investment is $31 per customer. The present price of a typical residential meter is $17. Now, the simplest form of present singlephase dual-register meter for recording onpeak and offpeak energy is $62 and it isn't even available in any kind of quantity. We have had 100 such meters on order for 3 months, and we don't even have delivery of them yet. This is not a mass-produced item to date.

In addition to the much higher cost of such a meter, Mr. Chairman, the annual cost of meter maintenance, meter reading, and billing will also be increased because of the increased complexity of the meters and more meter readings and more billing operations. For example, a residential electric meter, in its present highly perfected state, needs to be tested in Wisconsin, I think, only once every 12 years. Not too many years ago, we had to test them every 4 years. Presumably, if a much more complicated type of meter is used, the Public Service Commission would require much more frequent testing until the accuracy of such a meter has been determined.

If we were to replace our 75,000 residential meters at $62 plus installation, that would require an investment for our little company of over $5 million. If we had to replace 10,000 of the more complicated commercial and industrial metering installations, it would approach another $5 million.

This is one of the reasons, Mr. Chairman, why the utility industry has not just gone overboard for this kind of a thing because the equipment isn't available.

Also, on question No. 3, namely, is the smaller consumer being discriminated against when he or she pays twice as much as the large industrial customer, again I would speak only for Madison

Gas & Electric Co. I think an interesting statistic or two out of our annual report might be pertinent. Really, I don't think the small customer pays anywhere near that large a premium. For example, in our company in 1973, residential customers used 32 percent of the kilowatt-hours and brought in 36 percent of our total revenue. Commercial power and lighting customers used 43 percent of our kilowatt-hours and produced 45 percent of the total revenue. Industrial customers used 9½ percent of the kilowatt-hours, and produced 7⅒ percent of our total revenue. Public authorities, which is the State government and the University of Wisconsin and so on, consumed 13 percent of our kilowatt-hours, and produced 8 percent of the revenue. Now, I should explain that. Our largest customer, namely the university, pays a lower rate because they operate their own distribution system, buying power from us at only one location. So we have no distribution expense whatever there.

Therefore, we do not think the small customer is being discriminated against. And I may say that Wisconsin commission, I believe, has been over the years a very vigilant commission in its design of rates and approval of rates, and has not permitted that to happen.

There is, of course, some justification for the small customer paying somewhat more than the large customer because it does cost more to serve the small customer; 85 percent of our customers are small residential customers, and the billing, the meter-reading costs are the same for the small customer as for the large customer.

No. 4: Is the consumer being penalized for voluntary energy conservation through the imposition of higher utility rates? I guess I don't have to go into all the reasons why utility rates are higher. I think that the decrease in energy uses by conservation is probably the least of all of them. Higher fuel costs, higher labor costs, higher material costs, higher interest costs, pollution abatement equipment, all these things have contributed much more to the higher utility rates.

No. 5: On the investment tax credit, I would certainly second what Mr. Corey has said, and we feel our industry should be treated no differently than other industries. That is about as far as I would want to comment on that.

I would say again, I appreciate very much the opportunity to be here and hope that what we learn in Wisconsin, and particularly at Madison, through our new studies and experiments, will enable us to better serve our customers and do so with equitable rates.

[The prepared statement of Mr. Mackie, together with response to questions posed by Representative Moorhead follow:]

Prepared Statement of Frederick D. Mackie

Introduction

My name is Frederick D. Mackie. I am President and General Manager of Madison Gas and Electric Company, located at Madison, Wisconsin. I am appearing here at the invitation of Congressman William S. Moorhead, member of the Joint Economic Committee, to furnish information on factors which will influence the future rate of growth of electric demands and generating capacity and measures which can be used to improve the utilization of capacity.

Madison Gas and Electric Company is an investor-owned public utility engaged in the generation and transmission of electric energy and in its distribution in Madison, Wisconsin, and its environs (220 square miles), and in the purchase and distribution of natural gas in Madison and the immediately surrounding area (750 square miles). At October 31, 1974, it served 85,580 electric customers and 52,352 gas customers. The population in the Company's service area is approximately 215,000.

Madison's position as a governmental, educational, research, and medical center, and as a trading and distribution center for a diversified farming region has resulted in a relatively stable economy in the Company's service area.

Following is a table showing kilowatt-hour sales to ultimate customers during 1973, and the percent of sales of each customer classification:

	Electric sales, 1973	
	Kilowatt hours	Percent of total
Residential	471,424,000	32.7
Commercial power and lighting	628,488,000	43.6
Industrial power and lighting	139,157,000	9.6
Street and highway lighting	11,550,000	.8
Public authorities	191,962,000	13.3
Total sales to ultimate customers	1,442,581,000	100.0

The Company's market is atypical in that industrial sales are a substantially lesser percent of total sales than for most electric utilities. As shown above, 9.6 percent of sales are industrial sales, as compared to 25 percent to 35 percent, which is the range for most other utilities. Commercial sales at 43.6 percent and Sales to Public Authorities (primarily the University of Wisconsin) at 13.3 percent are indications of the governmental, educational, medical, and commercial character of the Company's market.

The energy requirements for the Company's electric system are supplied primarily by the Company's share of the jointly owned Kewaunee nuclear plant, which is located on the shore of Lake Michigan near Kewaunee, Wisconsin, about 150 miles from Madison, and by the Blount Street plant in Madison. The Company also operates five remote-controlled combustion turbine peaking units which are distributed over three locations on the outskirts of Madison. In 1975, the Company will also begin receiving energy from a jointly owned coal-burning Columbia plant near Portage, Wisconsin, about 30 miles north of Madison. We estimate that in 1975 approximately 40 percent of our customer's energy requirements will be supplied by nuclear power, 42 percent by coal, 10 percent by natural gas, 6 percent purchased power, and 1 to 2 percent by oil.

Our testimony is responsive to the following questions asked by Chairman William S. Moorhead in his letter dated November 21, 1974, a copy of which is attached.

Response of Frederick D. Mackie to Questions Posed by Representative Moorhead in the Letter of Invitation to Testify

Question No. 1. What long-term rate of growth in electricity-generating capacity do you anticipate will be necessary to meet future demands for electricity?

Answer. Prior to 1964, the Company's annual peak one-hour demand occurred in to the winter. During the past ten years, the Company's annual system peak demand has occurred in the summer, due principally to the installation of air-conditioning equipment by customers. While there has been an increase in electric space heating, principally in apartments, it is anticipated that such loads will not cause a reversion to a winter peak for at least 15 years unless natural gas and fuel oil supplies are drastically reduced.

The following tabulation compares system peak demands for summer and winter of each year beginning in 1960. The mean temperature shown is for the day on which the peak occurred.

NET PEAK DEMANDS

	Mean temperature	Net maximum hour megawatts	Percent over last year
Summer—year:			
1960	82	100.7	9.5
1961	70	109.6	8.8
1962	59	112.0	2.2
1963	82	134.2	19.8
1964	82	160.8	19.8
1965	83	169.4	5.3
1966	77	184.3	8.8
1967	74	192.8	2.4
1968	81	232.2	20.4
1969	80	234.9	1.2
1970	76	267.1	13.7
1971	84	282.6	5.8
1972	77	316.0	11.8
1973	82	349.8	10.7
1974	86	332.0	−5.1
Winter—Season:			
1959–60	8	106.9	5.8
1960–61	13	113.5	6.2
1961–62	8	121.6	7.1
1962–63	−10	135.9	11.8
1963–64	−5	146.8	8.0
1964–65	−2	160.1	9.0
1965–66	18	167.8	4.8
1966–67	−1	178.5	6.4
1967–68	2	196.0	9.8
1968–69	20	203.8	4.0
1969–70	−7	220.2	8.1
1970–71	6	226.6	2.9
1971–72	−1	246.9	9.0
1972–73	3	259.0	4.9
1973–74	24	252.4	−2.5

It is evident from this tabulation that: (1) the change from a winter peak occurred in 1964, and (2) the percent increase in demand fluctuates substantially from year to year. It can be seen that this is related to the average temperature on the day the peak occurred.

The annual rate of growth in peak demands during the past nine years has averaged 8.6 percent. The peak demand in the summer of 1974 was 5.1 percent less than 1973, and is the first time in many years that the peak demand has decreased. The decrease is attributed principally to conservation efforts by customers, to cooler weather, and the effect of inflation on consumers' spending for goods and services.

After careful analysis of planned construction in our service area during the next three years, and giving consideration to a number of factors which we anticipate will influence energy use during succeeding years, we estimate the rate of growth in peak demand will be approximately 6 percent as compared to the 9 percent rate experienced during the ten years prior to 1974. Factors considered include a diminishing rate of population growth, continued conservation of use by existing customers, the effect of new building codes which require construction designed to conserve energy, and the effect of other conservation efforts, such as greatly accelerated use of insulation by residential and commercial customers. The rising costs of all forms of energy, including electricity, is also believed to have a significant effect.

Offsetting the factors which will tend to lower the rate of growth of peak demand is the potential substitution of electric energy for other primary fuels. An increase in electric energy use for space heating would improve capacity utilization, but would not, in the near term, add to the summer peak. However, in larger commercial installations, substitution of electricity-driven air-conditioning equipment for gas or steam-operated equipment would add to summer peak demands. Substitution of electricity-operated industrial equipment, such as electric furnaces in foundries, could also increase peak demands.

Question No. 2. What has been the impact of recent energy conservation measures on producing a growth rate that differs significantly from historical standards?

Answer. Energy conservation measures, combined with several other factors, have materially reduced the rate of growth of both system peak demand and kilowatt-hour sales. The following tabulation compares system peak demands and maximum system daily kilowatthours, by months, for the years 1972, 1973, and 1974 through November:

NET MAXIMUM HOUR DEMAND

Month	System peak demands, megawatts			
	1972	1973	1974	Percent 1974 over 1972
January	246.9	254.0	233.5	−3.3
February	239.4	246.0	225.1	−6.0
March	231.0	238.0	224.0	−3.0
April	212.1	226.0	217.8	+2.7
May	261.4	227.0	247.8	−5.6
June	271.9	303.0	276.7	+1.8
July	311.3	311.0	332.0	+6.7
August	316.0	349.8	315.0	−.3
September	230.6	288.0	275.0	+1.6
October	238.4	252.4	239.0	+.2
November	251.0	252.0	249.0	−.8
December	259.0	243.2		

MAXIMUM DAY

Month	Maximum system daily energy, megawatt-hours			
	1972	1973	1974	Percent 1974 over 1972
January	4,326.8	4,688.0	4,450.4	+2.9
February	4,298.1	4,574.7	4,383.1	+2.0
March	4,167.5	4,431.0	4,249.1	+2.0
April	3,920.0	4,340.7	4,139.2	+5.6
May	4,603.2	4,281.2	4,541.4	−1.3
June	4,535.2	5,675.2	5,039.5	+11.1
July	5,952.5	6,039.6	6,295.4	+5.8
August	6,059.7	6,729.9	5,662.3	−6.6
September	4,885.7	5,522.7	5,229.3	+7.0
October	4,307.2	4,831.5	4,379.7	+1.7
November	4,407.3	4,448.8	4,448.4	+.9
December	4,766.3	4,366.8		

The following trends are evident:

(1) The 1973 summer loads did not increase materially over 1972. This was prior to the energy crunch. However, the weather in the summer of 1973 was significantly cooler than the summer of 1972.

(2) Starting in November of 1973, we note a significant decrease from the same months of 1972. This trend continues on through all of the months of 1974. Through November, 1974, our demand has been below the same months of 1972 and 1973.

This decrease is due in part to the energy conservation movement, in part to somewhat milder weather in the winter of 1973–74 compared with 1972–73, and in part to gradually worsening economic conditions.

It is not possible to determine exactly the impact of each factor but, in our judgment, the energy conservation movement accounts for a very substantial portion of it.

Question No. 3. To what extent can increased implementation of Peak-Load Pricing and Long-Run Incremental Cost pricing impact the demand for electricity-generating capacity?

Answer. One of the basic principles of rate design is that rates should promote an efficient allocation of resources, thus discouraging wasteful use of energy. This implies the use of the economic principle of marginal cost pricing. The marginal cost refers to the change in cost to produce one more unit. Under economic theory, an optimum allocation of resources results when the prices of goods and services are set equal to their marginal costs of production. The consumer will compare this price to the value to him of one more unit and will buy the extra unit if it is worth as much to him as it costs to produce it.

This concept of the cost of a single additional unit is impossible to apply to an electric utility, which adds generating units, transmission lines, and distribution facilities capable of producing or transporting more than a single unit of output and on a continuing basis. Therefore, for practical purposes, an alternative is the use of incremental cost, which refers to discrete blocks of additional production with associated costs expressed on a unit basis, and long-run rather than short-run additional costs of doing so. Long-run incremental cost is, therefore, the cost associated with meeting additional blocks of demands for electric power on a continuing basis.

Setting of rates for electric service using the results of long-incremental cost studies will then, theoretically, assist in the efficient use of electricity and it is probable that, to the extent wasteful use of electricity exists, the rates would discharge such use and the rate of growth of demand would be reduced.

Practically all the experience in this area is confined to England and France, where substantially different production, distribution, and marketing conditions prevail. Lacking domestic experience, we can only speculate as to the impact of such a pricing scheme on the demand for electric generating capacity.

First of all, the impact would, to some extent, be dependent upon the character of the market and customers served. I have already described the "non-industrial" market served by MG&E. This means that in order to achieve meaningful results, we must necessarily rely on small demand reductions from a large number of customers, exactly opposite from the situation which would prevail in a highly industrialized market.

To the extent that LRIC pricing results in higher rates for service, especially in the terminal blocks, we anticipate that such rates would have some decelerating effect on the growth of demand. The effect of peak-load pricing in a market such as the one we serve is more difficult to measure.

At the present time, neither physical facilities nor administrative procedures have been sufficiently developed to accurately measure the effect of peak-load pricing on residential customers or other mass customer classifications.

Question No. 4. What other measures besides peak-load pricing can we use to improve the rate of capacity utilization in the electric utility industry?

Answer. There are several means of improving load factor other than peak-load pricing. The most obvious if off-peak pricing. This practice has prevailed for many years, with off-peak water heating being one of the better known applications to mass customer classifications. The advantage of off-peak pricing is that it is not necessary to pinpoint the off-peak period, thus providing a rather broad range of hours of use as contrasted to the necessity for pinpointing peaks, the occurrence of which is often difficult to predict.

When seasonal rates are applied, the use of lower rates for terminal blocks during off-peak seasons likewise encourages more efficient use of production and distribution facilities. With development of more sophisticated control devices at reasonable costs, it may become possible to apply company-controlled load management procedures even to mass classifications. Normally, such procedures are limited to the relatively few large volume users. Load management embraces a variety of plans and control equipment configurations which are designed to reduce or flatten peaks by either total or partial short-term discontinuance of service during on-peak hours.

Another control method is the application of interruptible rates—again applicable to only a relatively few large volume customers. In return for the right to discontinue service during certain limited and specified on-peak periods, the rate for such customers is established at a level lower than that applicable to customers whose entitlement to service is continuous and complete. The natural gas industry has applied interruptible rates for many years. In some instances, several levels of interruptible rates are applied, based upon the relative priorities of service.

Question No. 5. Do you believe that peak-load pricing will have a significant impact on increasing the capacity utilization of generating equipment?

Answer. Since we are now only at the threshold of peak-load pricing, it is much too early to measure the anticipated impact on capacity utilization. The picture is further clouded by the uncertainty of the quantities and prices of alternative fossil fuels. Under more normal conditions, effective peak-load pricing might force some customers either to full or supplementary service from other energy sources. If viable alternatives are not available or cost too much, such customers will be forced to pay the higher on-peak rates with little, if any, shift in load from on peak to off peak. To add further to the uncertainties I have just enumerated, any extended continuation of present depressed economic conditions would render any forecast of the impact of peak-load pricing high speculative.

Question No. 6. What problems have arisen with the implementation of your peak-load pricing experiments?

Answer. Except for summer-winter differentials, the Company has not yet embarked on a full-blown program of peak-load pricing. However, I can tell you about some of the problems involved in getting started. The August, 1974 order of the Public Service Commission of Wisconsin did *not* prescribe any specific peak-load pricing beyond the seasonal rates proposed by the Company. What the P.S.C. did was set in motion the preliminary studies it deemed necessary to determine the feasibility or need for various forms of peak-load pricing. The P.S.C. ordered MG&E "to prepare and submit a study indicating the feasibility and effect on its customers of various forms of time-differential and load-rate pricing including interruptible service and time-differential and load-rate pricing including interruptible service and time-of-day-metering."

In response to the above-cited provision, on October 7, 1974, the Company filed the attached proposed methodology for conducting the study. This attachment sets forth in considerable detail the problems involved, and I believe it is responsive to that part of your inquiry with respect to problem areas.

Another potential problem is that of just shifting the peak from one season to another. For example, prior to 1964, when the Company's system peak demands occurred in winter, some improvement in load factor occurred during a period of approximately 17 years when the Company had summer off-peak rate schedules in effect. Under those rate schedules, commercial and industrial customers whose demands in summer exceeded winter demands were billed at a lower rate for the excess demand. With the increasing use of air-conditioning in the early 1960s, the Company's system peak demand shifted to summer and load factors again began to decrease. There was no economic justification for continuance of the off-peak rate. Current rates authorized by the P.S.C. of Wisconsin in August, 1974, while of different design, result in higher summer demand charges than in winter, which is an incentive for commercial and industrial customers to reduce summer demands. While summer-winter rate schedules are not expected to cause any appreciable shifting of system peaks toward winter, it is necessary to study and observe the effects of any kind of rate structure which may cause shifts of peaks on a daily or seasonal basis.

Question No. 7. What have you learned that might be helpful to other utilities which are considering peak-load pricing?

Answer. I think the attachment to which I have referred should be helpful to other utilities considering peak-load pricing.

Electric utilities which have large commercial or large industrial customers generally have greater opportunities to effectively use peak-load pricing as a control device than companies, such as Madison Gas and Electric Company, which have comparatively small industrial and commercial customers.

OTHER DISCUSSION

Following is a list of other materials which may be consulted for further information on the subject:

(1) Electricity Rates and the Energy Crisis: A Conference Report on the FEA-Sponsored Electricity Rate Conference held in Washington, D.C. on June 19, 1974.

(2) Proposed Study of Experimental Rate Structures and Off-Peak Storage Systems: By Ralph A. Whitney, Green Montain Power Corporation. Presented before Edison Electric Institute Rate Research Committee, Denver, Colorado, September 18, 1974.

(3) Contemporary Pricing: By Irwin M. Steltzer, President, National Economic Research Associates, Inc. before the E.E.I. Rate Research Committee, Lake Placid, New York, September 26, 1973.

(4) Findings of Fact and Order, Wisconsin Public Service Commission Decision and Commissioners' Opinions, Docket 2–U–7423. Application of Madison

Gas and Electric Company for Authority to Increase its Electric and Gas Rates.

Before the Public Service Commission, State of Wisconsin.

IN THE MATTER OF A STUDY OF THE FEASIBILITY OF TIME-DIFFERENTIAL AND LOAD-RATE PRICING: PROPOSED METHODOLOGY FOR CONDUCTING STUDY

INTRODUCTION

The Commission, in its Order dated August 8, 1974, in Docket No. 2–U–7423, ordered Madison Gas and Electric Company, and invited other Wisconsin electric utilities who may wish to cooperate, to submit a proposed methodology for conducting a study "indicating the feasibility and effect on [their] customers of various forms of time-differential and load-rate pricing including interruptible service and time-of-day-metering," to the Commission for authority to proceed. This proposal is submitted in compliance therewith.

PARTICIPANTS AND POSITION OF COMPANIES

Northern States Power Company (Wisconsin), Wisconsin Electric Power Company (and its subsidiary, Wisconsin Michigan Power Company), Wisconsin Power and Light Company, and Wisconsin Public Service Corporation, have indicated a preliminary willingness to participate in the proposed study in cooperation with Madison Gas and Electric Company. Other Wisconsin utilities will also be invited to participate. The scope of the proposed study, which will undoubtedly require substantial services from independent consultants, is predicated upon the support of at least the identified participants, and would have to be scaled down if the anticipated level of participation fails to materialize.

The study contemplated by the participant companies is for the purpose of determining whether or not time-differential and load-rate pricing is feasible to implement and appropriate to institute under current circumstances. The companies consider the potential economic and environmental benefits of new and more sophisticated forms of peak-load pricing sufficient to warrant serious study and consideration, with, however, two caveats that immediately come to mind. First, we would not expect the proposed exercise, even if fruitful beyond any reasonable expectation, to produce a single pricing mechanism suitable for utilization in the various service areas of the participant companies or throughout the state. Secondly, in our zeal to precisely correlate tariffs with anticipated costs, we should be mindful of the Supreme Court's admonition in *West Allis* v. *Public Service Comm.* (1969), 42 Wis.2d 569, at 577:

"It is well established that the Commission in designing a rate structure to recover the revenue to which it is entitled, as shown by a cost analysis, has wide discretion in determining the factors upon which it may base it precise rate schedule. It is not required to apply a cost-of-service formula to each class of customer or to each customer within a class."

It is entirely possible that the study may indicate that time-differential and load-rate pricing is not in the public interest. Accordingly, it should be understood that by proposing, or if authorized, by undertaking the study, the companies are not endorsing or committing themselves to any particular course of future pricing practice.

PURPOSE OF STUDY

As we understand it, the study ordered by the Commission contemplates a research plan designed to obtain the information necessary to give complete consideration to the feasibility, possible structure and likely effects of various pricing schemes which give recognition to the fact that the marginal costs of supplying electricity vary by time of day and by season of the year. While the concept of rates that vary from one time of the day to another and from one time of year to the next has been articulated for a number of years, the actual information required to design specific, potential rate structures and the practicalities of implementation entail a fairly significant amount of research. A wide range of methodological and empirical questions must be answered before a rational decision can be made as to whether implementation of time-of-day rates will likely effect the objectives sought.

GENERAL AREAS OF RESEARCH

There are five basic areas in which we propose to proceed with our research efforts: (a) methodologies for estimating the relevant marginal cost components and the transformation of marginal cost estimates into actual rates, (b) basic load research, (c) the usefulness, structure and costs of new rate forms, (d) metering capabilities and costs, and (e) the evaluation of alternative rate options and their applicability to different classes of customers, including relationship to revenue stability and impact on customer relations.

We believe that a series of important questions must be answered and alternatives considered in each of these areas in order to determine whether a comprehensive set of time-related rates should be applied to our customers. Certain aspects of this research may be completed fairly quickly and at a minimal cost. Other aspects of the research may require both considerable time and considerable expense. These five research areas are interdependent and the results in one may very well eliminate or redirect research in another.

In order to give the Commission a clearer understanding of the directions in which we propose moving, we outline below the kinds of questions we will be seeking to answer in each of the five research areas.

A. Costing and pricing methodologies

We propose to develop a methodology for estimating customer, demand and energy costs, using marginal cost techniques, by time of day and year, drawing on the relevant tools of economics and engineering as well as the experience in other countries. We will identify the kinds of cost information required and institute efforts to obtain it. In addition, we will seek to develop general methodologies for translating estimates of marginal costs into actual peak-load rate structures. We will be concerned specifically with techniques for identifying rating periods (peak, shoulder, off-peak), the allocation of capacity and energy charges to each period, and the incorporation of individual and class load characteristics such as load factor and diversity factors into peak-load rate structures, together with the associated administrative costs.

B. Basic load research

Detailed information on the system load characteristics and the load characteristics of particular types of customers is critical for establishing peak-load rates and predicting the likely effects of various rate alternatives. We propose to expand existing load research programs to gain information on the consumption patterns of different types of customers, the mix and saturation level of major appliances for residential and commercial customers, and the nature of the industrial processes used by our larger industrial customers. This research will involve the acquisition and installation of additional recording meters on selected customers as well as market research efforts. The information will be used to identify both "typical" and "atypical" consumption patterns and will constitute an important input into any final rate structure proposal.

C. Tariff determinations

Where metering costs are small relative to the costs of supplying customers (the large industrial and commercial customers), we can proceed from steps A and B to the design of possible rate forms for such customers.

For all other customers, with relatively significant new metering costs, the choice of the appropriate rate structure turns on the effects, in terms of resource savings, that are likely to result. It would not make sense, for example, to implement a time-of-day rate structure which required the expenditure of $100 on additional metering if the value of resources saved were to be only $50.

Some rate improvements may be made without extensive metering changes and these should be explored and specified. As for changes requiring expensive changes in metering, before embarking on large investments in new meters for our smaller customers, we suggest that the pros and cons of conducting a controlled experiment to assess the effects of alternative peak-load pricing schemes be carefully weighed. Since time-related rates have been used only to a limited extent for residential customers in Europe and even less so in the United States, our current knowledge of the likely effects of such rates is very limited. We propose to investigate exactly what such an experiment would entail, provided such an experiment may be lawfully conducted.[1] What kinds of rates should be tried? How large would the samples have to be? How long would the experiment have to last? How much would the experiment cost? How do we evaluate the results? This information must be obtained to enable us to decide whether or not an experiment is justified, what form it should take, and the relative attractiveness of various alternatives to experimentation that might be developed. We are aware of the British Domestic Tariffs Experiment and will look to it for suggestions. We believe, however, that specific results of that study are of limited applicability to our situation, for a variety of reasons, theimportance of air-conditioning load in Wisconsin, but not in Britain, being one of these. Another is the likelihood that there have been positive developments in metering technology since that experiment was initiated.

D. Metering capabilities and costs

We know that the capability to effectively meter tariff structures of ever increasing complexity may involve considerable expense. A line must be drawn between increasing capability and increasing metering cost. Our research effort here would be designed to find out what kinds of metering capabilities are available today or likely to be available in the near future and what the likely costs of these capabilities are. We will attempt to evaluate and cost of these metering alternatives not only in terms of their time-related metering capabilities narrowly defined, but will also examine the feasibility of their use for interruptible rates and direct load management. The output of this part of the research effort will be a study documenting the capabilities and types of metering technologies available, their expected costs and an evaluation of their reliability.

E. Alternative rate structure options

A variety of rate structure options, from the farily simple to the very complicated may be in the spirit of long-run marginal cost pricing. We will seek to develop a wide variety of options including not only seasonal and time-of-day rates but also interruptible rates and various load management alternatives to which would be attached price incentives. As information is developed in the other four research areas we will attempt to make calculations of what such rate options would actually look like based on actual marginal cost calculations, and how much the alternatives would cost to administer and meter. Using these calculations, we will attempt to determine which rate options should be associated with which types of customers to yield the greatest net benefits and what the impacts of such new rates would be on the charges that would be levied on a set of typical customers compared to what they pay under existing rate structures. We view this as the final step of the proposed research program.

No doubt additional questions will develop as our research proceeds. Those that are important to our understanding of time-related rates will of course be pursued. Our hope is that as our research proceeds we will obtain the necessary information to talk about and make recommendations regarding rate structure alternatives in a more intelligent and concrete way than any party has been able to do to this date, especially regarding the specific conditions that we face here in Wisconsin.

CONCLUSION

We propose to begin these research efforts immediately following authorization, and six months thereafter submit a detailed outline of each of the five study areas indicating estimated manpower requirements, costs, and schedules along with signed agreements of participating companies including the

[1] A threshold, legal problem is whether a meaningful experiment of the sort envisioned may be conducted under the anti-discrimination laws, without specific, enabling legislation.

method of allocating costs of the project. Thereafter, we propose reporting to the Commission at six month intervals the results of the evolving research and the implications of new future rate forms, including of course observation of the probable interaction between such rate forms, customer usage and cost conditions.

Dated this 7th day of October, 1974.

Respectfully submitted,

MADISON GAS AND ELECTRIC COMPANY
By: FREDERICK D. MACHIE

Before the Public Service Commission of Wisconsin.

APPLICATION OF MADISON GAS AND ELECTRIC COMPANY FOR AUTHORITY TO INCREASE ITS ELECTRIC AND GAS RATES—2–U–7434

FINDINGS OF FACT AND ORDER

Summary of Proceeding

Madison Gas and Electric Company (Applicant) filed an application with the Commission on March 3, 1972, seeking authority under sections 196.03, 196.20, and 196.37, Wis. Stats., to increase its rates for electric and gas service in an amount sufficient to return 8.4% on net investment rate base, the level of return previously authorized by the November 10, 1970 Order in Docket No. 2–U–7037 (55 PSCW 666) pertaining to rates for electric service. At a hearing held May 24, 1972, Applicant refined its request to seek $3,130,719 in additional electric revenue and $1,429,934 in additional gas revenue to achieve above-recited, the rate of return, based on a 1972 test year.

On August 25, 1972, Applicant amended its application to request an interim increase to produce the above-recited return on average net investment rate base using operating income projections for 1972; in addition, Applicant sought permanent rate relief calculated to produce a 13% return on common stock equity capital using projected operating income for 1973.

Pursuant to due notice, hearings were held at Madison on May 24 and September 11, 12, 13, and 14, 1972, before Examiner Clarence B. Sorensen regarding both the initial application and the subsequent request for interim relief, at which hearings both the Applicant and the Commission staff presented testimony. With respect to the *interim* case, testimony was complete and the case closed on September 14, 1972, and an interim order was issued on October 5, 1972, authorizing interim rates to produce a return of 8.49% on rate base (57 PSCW 463). Thus, based on the test year 1972, rates were adjusted to generate additional annual revenue of $2,581,082 for Applicant's electric service and $1,587,982 for its gas service.

Further hearings respecting permanent rates were held at Madison on October 17, 18, and 19, 1972, wherein Applicant presented evidence based on projected results for the test year 1973. Applicant requested, in addition to the interim rate increase authorized in the order of October 5, 1972, and based on the test year 1973, authority to increase electric rates to produce additional annual revenues of $4,001,945 and gas rates to produce additional revenues of $1,310,061. Intervenors offered evidence relating to electric rate structure.

Further hearings were held at Madison on December 19, 20, and 21, 1972, to consider test year revenue requirements, gas rate design, and temporary electric rate design to produce the required revenu pnding final determination of electric rate structure. The record with respect to matters other than permanent electric rate design was closed on December 31, 1972. In the December 1972 hearings, Applicant proposed electric and gas rates designed to recover 1973 test year revenue requirements, and the Commission staff presented evidence with respect to revenue requirements for the test year.

On February 13, 1973, an order was issued establishing final rates for gas utility service and temporary rates for electric utility service to remain in effect until further order of the Commission. Based on projected results for the test year 1973, an increase in electric utility revenues of $2,121,300, and an increase in gas utility revenues of $1,425,900 were authorized.

Further hearings were held at Madison on August 20, 21, 22, 23, and 24, 1973 and on January 21 and 22, 1974, to consider the question of electric rate design. The record for the case was closed on January 22, 1974. In the January 1974 hearings, testimony was presented by intervenors and Applicant relating to the possible effects of changes in rate design on the environment and on the manufacturing industry in Wisconsin.

Briefs were filed by Capitol Community Citizens and Environmental Defense Fund, hereinafter sometimes referred to as "CCC-EDF," Robert Owen, Wisconsin Manufacturers Association, and Associated Milk Producers Incorporated. A reply brief was filed by the Applicant. Replies to the reply were filed by CCC-EDF and Robert Owen, the last of which was received April 22, 1974. On May 7, 1974, oral arguments were presented by John A. Hansen, Counsel for the Applicant; Edward Berlin, Counsel for CCC-EDF; and Melvin Goldberg, Counsel representing Mr. Owen.

At various times in the course of the hearings herein, Chairman Eich presided and Commissioners Padrutt and Cudahy, and former Commissioner Komar participated. Appearances at such hearings are set forth in Appendix A attached hereto.

DESCRIPTION OF APPLICANT

Applicant, Madison Gas and Electric Company, is an electric and gas public utility, as defined in section 196.01, Wis. Stats., engaged in the production, transmission, distribution and sale of electric energy to approximately 78,000 retail customers in the city of Madison and certain of the surrounding areas in Dane County, and the distribution and sale of gas to approximately 48,000 retail customers in the city of Madison and certain of the surrounding areas of Dane County, and in the city of Lodi and rural towns in Columbia County. All of the Applicant's common stock is held directly by individuals and entities other than holding companies.

DISCUSSION OF ISSUES

Inasmuch as the hearings on the matter of electric rate design for Madison Gas and Electric Company in this docket involved considerable presentation and discussion, these matters will be discussed in general terms in this section of the Order. These principles, in general, apply to other electric utilities under this Commission's jurisdiction facing similar operating conditions and are not limited to MG&E in this docket. Specific findings of fact on these issues will follow.

I. Principles and practices of rate design

Many witnesses in this case have testified on the subject of basic principles of rate design. The suggested basic principles alluded to most frequently in this proceeding are:

1. Rates should promote an efficient allocation of resources, thus discouraging wasteful use of energy.
2. Rates should not be discriminatory.
3. Rates should lead to stable revenues.
4. Rates should reflect a sense of historical continuity.

There was reasonably general agreement among all parties that the first principle enumerated above implies that rates should properly reflect the marginal cost of providing service to a given customer.

The widely prevailing practice among electric utilities today concerning rate structures calls for recovery of customer costs—i.e., costs which do not vary with use—in the first one or two consumption blocks. Often, a portion of the customer costs are collected through a fixed charge. The third and following blocks generally exhibit a declining price level with increased sales in order to reflect the economies of scale which result from increased output. This typical profile of a rate schedule will be referred to herein as a "declining block rate structure." This order covers the first comprehensive hearing testing the appropriateness of these traditional rate designs in view of new and different conditions faced by the public utility industry.

II. Long-run incremental costs

A modification of current practice was advocated by Dr. Stelzer, appearing as a witness for the Applicant. He suggests that the economic principle of marginal cost pricing be adopted and implemented in the form of rates based on long-run incremental costs—hereinafter often referred to as "LRIC."

The "margin cost" of an item refers to the change in cost that occurs with infinitesimally 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 production, an optimum allocation of resources results. This occurs because the price will reflect the cost to society of producing one unit of the good. The consumer will compare this price to the value to him of one more unit and will then buy the extra unit if, and only if, it is worth at least as much to him as it costs society to produce it.

A major obstacle to the application of marginal cost pricing to electric utilities is the problem of measuring marginal costs. In order to discuss the measurement, it is necessary to carefully determine and define exactly what is to be measured. Theoretically, the economically efficient price, as discussed above, is set at the short-run marginal cost (SRMC) of the smallest possible additional unit of sale. However, rather than short-run marginal cost, long-run incremental cost has been suggested as the logical surrogate for marginal cost. Long-run incremental cost is the incremental cost of the capacity and output which can reasonably be expected to be added in the next several years. There are two reasons for looking to LRIC. The first is practicality. Long-run incremental cost lends itself to measurement while short-run marginal cost does not. The second, and more basic reason, is that if electric utility rates were tied to short-run marginal costs they would be extremely volatile. Such rapidly fluctuating rates would deprive consumers of those expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of service.

Applicant has provided estimates of MG&E's LRIC in this proceeding. The study divides LRIC into the three following components:

1. *Customer cost.*—This component includes meter reading, billing, connection costs, and that part of distribution costs that has been designated as varying only with number of customers.

2. *Demand costs.*—This component includes generation, transmission and distribution capacity costs that vary with total kilowatt demand. These future costs are estimated on the basis of expected expenses adjusted to the current price level of actual additions to plan anticipated by the utility. These costs do not vary with number of customers but equal the sum of the capacity commitments made by the utility when providing service to customers. These costs are the same whether the customer buys energy only at system peak or buys the same amount continuously over the year.

3. *Energy costs.*—This component includes the operating and maintenance costs associated with supplying a given number of kilowatt-hours of energy. These costs vary directly with the amount of energy consumed by the customer's facilities.

The record shows a general acceptance of the principle of basing rate design on long-run incremental cost; howevtr, intervenors did question certain issues relating to the estimates of LRIC.

Substantial differences of opinion centered on the proper treatmeat of inflation in the cost study. Several intervenors argue that the estimated capacity costs, construction costs, and other utility costs should reflect future expected inflation. There was also some disagreement concerning the allocation of costs between customer and demand categories. Certain intervenors felt that an excessive amount of distribution costs was being placed in the customer cost category. However, only one LRIC study was presented and the opportunity to make an evaluation of different apportionment of costs was thus limited.

We believe that the appropriate benchmark for the design of electric rates in the case is marginal cost as represented by the practical variant, long-run incremental cost. If electric rates are designed to promote at efficient allocation of resources, this is a logical starting point.

It must be understood that the "long-run" concept is pursued as the most appropriate and most practicable cost measurement. The fact that "long-run" incremental cost is being used does not imply that the resulting rates will be valid for a long time into the future, nor that they will compensate for inflationary cost increases. The primary objective that LRIC-based rates are intended to accomplish is to guarantee an efficient allocation of resources directed toward the production of electricity. Applicant's estimate of future costs in terms of current dollars is consistent with the economic definition of long-run costs. If it is desired that there be a guard against the attrition of earnings which might result from future inflation, the appropriate mechanism for such allowance must be embodied in the calculation of the overall revenue requirement.

The allocation of costs is necessarily subjective and a number of theories of cost allocation, particularly as they apply to capacity costs, have been applied to electric rates from time to time. It should be noted that although a fully-allocated cost study must, by definition, allocate all items of cost, there are certain items of cost that may be omitted from an incremental lost study. To the extent that fewer costs must therefore be allocated, the incremental study is less dependent upon subjective valuations.

III. Peak-load pricing

A fully implemented application of LRIC pricing would be reflected in price differentiation for on- and off-peak sales. A first approximation to such peak-load pricing is the winter/summer differential which has been proposed by the Applicant. The winter/summer price differential reflects the costs of a seasonably peaking electric utility better than a year-round rate. The application of the winter/summer differential to a summer-peaking utility such as MG&E does not charge the space-heating customer for the cost of additional summer capacity, since the space-heating customer is using excess capacity.

Another type of peak-load pricing discussed in this record is interruptible service. Under such a rate, customers could avoid being charged for additions to capacity by agreeing to use electricity only at off-peak times. Interruptible rates have been made available by various Wisconsin electric utilities at various times. Such rates have not proven popular.

Full peak-load pricing applied to electric rates must take the form of time-of-day metering. Under such a plan, rates would vary with the time of day in order to reflect the true cost of peak demand. Customers are compelled to pay for the actual cost they are imposing on society and are rewarded for shifting consumption to an off-peak time, thereby improving the utility's load factor. The winter/summer differential does not offer such an alternative. Summer air-conditioning use cannot be postponed until winter.

The cost associated with the installation and use of the equipment necessary to implement time-of-day metering is not known, nor was any evidence submitted on this point. Whether the improvement in system load factor warrants any additional outlay for metering depends on the elasticity of demand at various times of day. However, the recording-type metering equipment already in use for many commercial and industrial customers lends itself to time-of-day metering at a negligible cost. In this area an investigation into the possible benefits of such a pricing system should begin without delay. Such a pricing system could result in lower costs to the large users as well as on improved system-load factor for the utility.

The Applicant will be ordered herein to investigate the feasibility of such a pricing system. Since the results of such a study could have an important impact on all electric utilities in Wisconsin, we deem it desirable for several of the large private electric utilities to cooperate in such a study.

IV. Cost structure

Applicant's witnesses calculated the revenue that would be derived if rates for all classes were set so that class revenues were equal to their respective incremental costs. This was compared to Applicant's total revenue requirement.

This comparison showed that revenues which would be generated by the rates set equal to LRIC would be approximately equal to the company's revenue requirement. The implication of this result is that Applicant cannot be experiencing "increasing costs" as defined by economists since "increasing costs" would imply that the rates set equal to LRIC exceeded the revenue requirement.

The reasons initially cited in support of the claim that MG&E is in an "increasing cost" situation centered on arguments showing historical increases in generating cost per kWh, which confounds the notions of "increasing costs" due to increased production vs. "cost increases" due to other factors such as inflation. Intervenors accepted this distinction later in the proceedings but still suggested that the inclusion of external costs as a part of total LRIC would result in the conclusion that MG&E is an "increasing cost" industry. They asserted that this conclusion would follow, since external costs increase disproportionately more than associated increases in output.

For the reasons outlined under heading VI below, the Commission does not consider it appropriate to include external costs in the cost study. Thus, analysis of the facts presented indicates that the claims that Applicant is in an "increasing cost" situation are not correct.

V. *Elasticity of demand for electricity*

Estimates of the elasticity of demand for electricity in Wisconsin were prepared by Dr. Cicchetti, expert witness for intervenors. This study estimated the elasticity of demand by broad customer classes. The results of this study indicated that the elasticity of demand for electricity is greater than zero.

While the record indicates the desirability of having specific information relating to the demand for electricity, this study is not a satisfactory working model for application in this rate case. A study that estimates the elasticities of demand within blocks of consumption would be more applicable for present purposes than the estimates by broad customer classes provided in this study. Additionally, some measure of the price elasticity at peak and off-peak would be especially useful in attempting to determine the feasibility of various forms of peak-load pricing.

VI. *External costs*

There was much discussion in this record concerning external or social costs. These costs are imposed on society but are not borne directly by the transacting parties. The discussion in this proceeding regarding external costs dealt primarily with the practicality of charging for these costs.

Dr. Olson, expert witness appearing for CCC-EDF, suggested that external costs could only be reflected by imposing a tax on the utility. It is, of course, beyond the province of this Commission to impose such a tax. Dr. Stelzer has stated that these external costs should be reflected in the incremental costs on which rates are based to the limited extent to which they are quantifiable, but he warned that including such costs for the purpose of electric rates, but not including them in the rates of its substitutes, could cause an uneconomic *shift* of resources rather than simply more efficient use of electricity. Professor Cicchetti has observed that, due to the problems involved in accurately reflecting external costs in rates, it might be more plausible to simply try to reduce such costs.

Although we intend to explore Dr. Stelzer's view we feel that, in general, taxation is the most appropriate vehicle for recognizing externalities. This issue involves broad questions of policy crossing multiple industrial and energy lines. To recover external costs solely from utility customers through their rates without assessing similar costs in the prices of other energy and industrial products would probably discriminate against utility customers.

VII. *Rate structure*

A central issue raised in this case was the appropriateness of the declining block rate structure. Alternatives to the declining block structure discussed are "flat rates" and "inverted rates." A "flat rate" structure consists of a fixed charge plus one rate per kilowatt-hour applied to all consumption. The "inverted rate" structure imposes higher energy charges for greater levels of consumption.

Factors relating to the appropriateness of the declining block rate structure that have presented in this case include the following:

1. The relationship of LRIC to the revenue requirement.
2. The importance of stability of rate structure.
3. The treatment of customer related costs.
4. The relationship between load factor and level of consumption.

The relationship between LRIC and the revenue requirement was discussed in part IV where it was determined that rates equal to LRIC would approximately equal Applicant's revenue requirement. This relationship points to the desirability of flattening the rate structure.

Customers of public utilities are entitled to rates for service which are reasonable and just. They therefore expect that the structure of rates will remain reasonably stable and make purchases of durable goods on this assumption. While we consider this to be an important factor in rate design, we do not feel that our approval of a flat summer residential rate in this case is contrary to the customers' reasonable expectations of stability.

Customer-related costs are costs which remain constant with respect to changes in either consumption or demand. They ostensibly vary only as the number of customers vary. These costs are currently recovered in part through a fixed charge, and the remainder is spread over the early consumption blocks. A strictly cost-related approach to customer costs calls for such costs to be recovered entirely by a fixed charge. Applicant, however, has suggested several reasons for not recovering all customer-related costs through a fixed charge. These reasons include the fact that customers strongly object to payments not associated with the quantity of electricity used. Also, if customer costs are overestimated a spreading of these costs will tend to offset the impact of any overestimation.

Intervenors claim that such spreading of customer costs is inappropriate as a matter of economic logic, and that it magnifies the differential between the early blocks and the tail block, fostering the belief that electricity is cheap when used in large amounts.

It is our opinion that, inasmuch as rates are to be based on costs, it is appropriate that fixed monthly charges reflect customer-related costs to the extent to which they have been reliably established.

Since current fixed charges are considerably below customer-related costs, the resulting increase would appear too great to accomplish at one time. However, a reasonable step in this direction can be taken at this time and the customer should be aware that further adjustment of fixed monthly charges toward total cost levels will be a consideration of this Commission in future proceedings.

If load factor improves with the level of monthly consumption in a given customer class or sub-class, then this fact, coupled with LRIC theory, would be reflected by declining block rates. There is no evidence demonstrating such a relationship, or lack of it, in this docket. We consider it important that in future rate cases electric utilities provide empirical information demonstrating a relationship between annual system peak-load factors and amount of usage by class, sub-class or by individual customer.

VIII. Applicant's proposals and commission adjustments

Based on Applicant's interpretation of the above issues, rates have been proposed designed to produce annual revenues of $32,275,070. Proposed rates differed from existing temporary rates with respect to both inter- and intraclass revenue distributions.

Interclass Differences

Except for the de minimis category of Capitol Heat, the largest single difference between existing temporary rates and proposed rates is that the proposed A.C. Power rate schedule, Cp–1, is designed to produce $100,639 more than under the temporary rates. This represents a further 2% increase for this class of customers. While this proposed change is in the direction indicated by Applicant's LRIC study, it is only a token movement in that direction. A greater movement toward LRIC cost levels is indicated as proper from the record, and the rates authorized herein will increase the revenue derived from the A.C. Power rate schedule by 8% over existing temporary rates.

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Other classes receiving increases under the proposed rates are the University of Wisconsin—$13,085 = 0.5%; the Capitol Heating Plant—$3,954 = 5.2%; and Municipal Water Pumping—$560 = 0.2%.

The class receiving the greatest decrease under the Applicant's proposal is Commercial Lighting and Power, Cg–1. The proposed rates would produce $99,962 less than existing temporary rates, a 0.9% decrease. This class is currently being charged at rates in excess of its LRIC and thus should receive the benefit of the shift of revenue responsibility toward the A.C. Power customer. Our order results in a greater decrease for the Commercial customers than that proposed by Applicant.

Other classes receiving revenue decreases under the proposed rates are residential, Rg–1—$1,462 = 0.01%, A.C. Power, Optional CpO–1—$528 = 1.5%; and Oscar Mayer Co.—$250 = 0.08%.

Applicant's basic proposed shift in the distribution of revenue responsibility between classes is from the commercial to the industrial class. Applicant has suggested two reasons for this. First, the Cg–1 is a higher load factor use, but present rates provide for a higher revenue realization for these customers. Second, existing rates make it advantageous for most power customers to receive service separately, rather than in combination with their lighting service. For this reason, Applicant desires to combine the two services under a single schedule at some point in the future. The rates authorized herein go further than Applicant's proposal in that we have increased power rates and decreased commercial rates considerably more than Applicant had proposed.

Residential rates

Applicant has proposed energy charges which include a winter/summer differential for rate schedule Rg–1. The proposed rates will lower the charge for 1,000–1,500 kWh in the winter months and increase charges for consumption in excess of 500 kWhs in the summer. The resulting differential is 0.56¢/kWh for use over 1,000 kWhs. The proposed fixed customer charge is not changed from the present level of $1.00.

We have determined that the record does not justify the declining block structure proposed by Applicant, and the order approves a flat residential rate with a winter/summer differential amount to 0.70¢/kWh for use over 1,000 kWhs. We also have increased the fixed charge to more properly reflect total customer-related costs. In addition, the first consumption block exceeds the level authorized for all other consumption in order to recapture further customer-related costs.

Commercial rates

Applicant's proposed rates for Commercial Lighting and Power schedule, Cg–1, include a winter/summer differential in the demand charges for measured demand in excess of 10 kW per month. Slight adjustments are made in the energy charges and winter demand charges. Significant changes are made in summer demand charges, the greatest difference being a 33% increase in the tail block.

The minimum charge, which includes the first 10 kW or less of demand, is presently $1.50, and the proposed rates retain this minimum for both winter and summer months.

This proposed shift of revenue responsibility from the energy to the demand charges is in keeping with Applicant's LRIC study. In this order we have increased the minimum demand charge from $1.50 to $2.00, and have lowered energy charges further in order to accomplish the shift of revenue responsibility toward the A.C. Power customers and bring rates closer to long-run incremental cost.

Industrial rates

Applicant proposed changes in the Cp–1 power service schedule quite similar to those proposed for the Cg–1 classification. The only substantial changes proposed for this rate schedule occur in the demand charges for summer months. The demand-charge tail block in this case is increased by 60%.

Unlike the Cg–1 schedule, a winter/summer differential is proposed for the first 10 kW or lessof demand. This is because a very substantial number of commercial and industrial air-conditioning customers take service under this schedule.

In order to accomplish the further shift of revenue responsibility discussed above, we have adjusted energy rates above Applicant's proposed levels under the Cp-1 schedule.

Other rates

The optional power service rate CpO-1 is a convenience rate and most of the customers served on this rate have low load factors. Applicant has not proposed a winter/summer differential in this class, and its proposed rates provide for a substantial increase in the demand charges and a substantial decrease in the energy charges. The net result is a slight overall increase in revenue.

Changes are also proposed in the Municipal Water Pumping rate Mp-1, the Oscar Mayer rate, Sp-1, the University of Wisconsin rate, Mg-1, and the Capitol Heating Plant rate, Sp-2. The nature of the proposed change in these rates is increased demand charges and decreased energy charges. Our order authorizes these rates as proposed by Applicant.

No changes are proposed or authorized in the following rate schedules: Rw-1—residential controlled water heating; Gf-1—miscellaneous flat rate service; Mls—flood lighting; CgT—commercial temporary service; Mg-2—secondary service for municipal defense sirens; Ms-1, 2, 3, 4, 5, 6, and 7,—various outdoor lighting rates.

Findings of Fact

The Commission finds:

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

2. Long-run incremental cost (LRIC) as defined and estimated by expert witnesses in the proceeding provides a reasonable approximation to marginal cost.

3. Implementation of pricing on the basis of LRIC requires that rates charged peak customers exceed those charged to off-peak customers. Full peak-load pricing, including different day- and night-time rates must, for large customers, be implemented without delay. As to smaller customers, the cost of metering is a deterrent factor, but experimentation and development of appropriate systems must go forward promptly. Applicant must forthwith undertake, either alone or in concert with other Wisconsin utilities, experimental work in this area.

4. Elasticity of demand for electricity is an important consideration in rate design in conjunction with LRIC pricing. However, the evidence in this case does not demonstrate the magnitude of the effect of such considerations and does not provide a satisfactory working model that can be used as a guide for determination of proper rates at this time.

5. It is reasonable and just to recover all customer-related costs through a fixed charge, and at this time, said costs can be partially recovered in the first block. The current practice of spreading such costs through more than one consumption block is no longer reasonable and proper.

6. Flat rate design is reasonable and just and a proper means of recovering energy and demand costs. Movement in this direction within limits imposed by equity is undertaken herein. It will be necessary for Applicant to demonstrate a changing relationship between levels of consumption and load factor to justify any declining block rate structure for any given class of service.

7. Based on the long-run incremental cost study presented in this matter, it is reasonable and just that rates should be authorized which increase the A.C. power rate schedule, Cp-1, by a greater degree than proposed by Applicant.

8. Winter/summer rate differentials provide a reasonable and just first step toward implementation of peak-load pricing.

9. The general shift of responsibility from energy charges to demand charges as proposed by Applicant in those rate schedules which distinguish between such charges is cost justified and is reasonable and just as an interim measure, but must be carried further in future cases.

10. Applicant's proposed A.C. Power energy charges do not appropriately reflect corresponding long-run incremental costs as developed herein. These charges are appropriately increased and as modified such rates are reasonable and just.

11. Rates proposed by Applicant for rate schedules CpO–1, Mp–1, Sp–1, Mg–1 and Sp–2 and all other rates authorized herein are reasonable and just. A summary of distributions of revenue between classes under rates in effect prior to this case, under existing temporary rates and under rates authorized herein are provided in Appendix C.

12. Despite findings with respect to the reasonableness and justness of rates as authorized herein within the present context of rate design and metering, the use of much more precise time-differential pricing to charge fully for costs of capacity is essential to meet modern cost conditions and to give full effect to marginal cost pricing. This can be accomplished through prompt and energetic experiment.

Conclusions of Law

The Commission concludes:

1. That the Commission is empowered by sections 196.03, 196.20, and 196.37, Wis. Stats., to authorize Applicant to establish rates in accordance with the above Findings of Fact; and that such an order should be issued.

2. That the Order herein does not constitute a "major action significantly affecting the quality of the human environment" as those words are used in section 1.11, Wis. Stats. Hence, preparation of an Environmental Impact Statement is not required, nor are any of the other requirements described in section 1.11, Wis. Stats., applicable to the proceeding. Compare *Application of Wisconsin Electric Power Company for Authority to Increase Its Electric Rates*, Docket No. 2–U–7131, order after rehearing dated August 1, 1973.

Order

The Commission therefore orders:

1. That Madison Gas and Electric Company be and it hereby is authorized to substitute for its existing electric rates the rates specified in Appendix B, attached hereto, which are designed to produce $32,275,070 annual revenue.

2. That this Order and the rates authorized herein shall be effective for service rendered on September 16, 1974, and thereafter or on the effective date specified in the Order to the Commission in Docket No. 2–U–7952, whichever is earlier.

3. That Madison Gas and Electric Company shall prepare bill inserts which appropriately identify the monthly rates authorized herein. A copy of such insert will be submitted to the Commission for approval. Distribution of said insert shall be made to customers with the first billing which contains the rates authorized herein.

4. That Madison Gas and Electric Company be and is hereby ordered to prepare and submit a study indicating the feasibility and effect on its customers of various forms of time-differential and load-rate pricing including interruptible service and time-of-day-metering. This study need not be an independent endeavor, but may be conducted jointly with other Wisconsin electric utilities who may wish to cooperative with Madison Gas and Electric Company on said study. Within 60 days of the date of this Order, proposed methodology for the various phases of this study should be submitted to the Commission for authority to proceed. Reports of all relevant developments shall thereafter be submitted at intervals of 6 months (unless waived for a particular interval by the Commission without hearing), including a final report to be submitted as the Commission shall further direct without hearing.

5. That the motions relating to the preparation of an Environmental Impact Statement as a part of this proceeding herein be and the same are hereby denied.

6. That any other motions or requests not specifically mentioned herein are denied, dismissed or disposed of in a manner consistent with the order herein.

Concurring opinions by Chairman William F. Eich and Commissioner Richard D. Cudahy and dissenting opinion by Commissioner Arthur L. Padrutt are attached.

Dated at Madison, Wisconsin, August 8, 1974

By the Commission.

JOHN T. GOETZ, *Secretary*.

WILLIAM F. EICH, CHAIRMAN, CONCURRING: 2–U–7423

Just as this case has been like no other in the Commission's history, today's order, in its detailed and wide-ranging analysis of the socio-economics of electric rate design, is unique. The hearings covered eighteen full days over a period of nearly two years, and the transcript of testimony (exclusive of exhibits) fills some 3000 pages. What began as a rather routine proceeding involving a medium-sized utility became, with the intervention of the Capitol Community Citizens and the Environmental Defense Fund (EDF), a "national" test case on electric rate design.

Electric rate structures have traditionally been based on declining block schedules which incorporate a form of quantity discount pricing—the more units (kilowatt hours) used, the lower the unit price.[1] The central economic assumption underlying the declining block rate structure is that the cost of a utility's generating and transmission capacity is a fixed cost, and, as electricity output increases, this fixed cost will be spread over more units and thus the average cost per kilowatt hour (kWh) will decline as larger quantities are consumed.

There is little doubt that an additional (and intended) function of such a structure has been to promote greater usage of electricity.[2] The period during which declining block structures were developed was, after all, a period when the policy of government and the utilities alike was one of promoting the widespread and ever-growing use of electricity. It should be obvious that those days are gone—probably forever, yet electric rates are still structured to encourage the use of additional electricity during maximum or peak usage periods, and it is precisely such usage that spearheads the need for additional generating capacity, with all of the attendant economic, environmental and social costs. That is what this case is all about—the need to revise these outdated rate structures to reflect current demand and the true costs of meeting that demand.

To this end, we have adopted the concept of long-run incremental cost as the touchstone of our ratemaking policy, and have established a presumption that rate differentials which benefit large-volume users (e.g. declining block rates) are generally not justified; and in the future it will be incumbent upon those utilities advocating retention of such rate design features to clearly demonstrate their cost justification. We have gone further in this case by ordering essentially flat rates in certain service classifications—particularly the summer residential rates—and in addition to adopting a summer-winter rate differential reflective of the demands placed on the system by air conditioning loads, we have directed the company to institute experiments on time-of-day metering to determine the feasibility of eventual adoption of a full peak-responsibility rate design.

Because the disposition of these and other issues raised in this proceeding involve some new directions for the Commission, I feel they deserve individual, as well as collective, discussion.

1. LONG-RUN INCREMENTAL COSTS

The several economists testifying in these proceedings advocated (naturally) an "economic approach" to ratemaking—that is, one which is conducive to the efficient allocation of resources, including environmental resources. There was no significant disagreement among the economic witnesses for the company and the intervenors on the propriety of achieving these goals by basing rates generally on a variant of "marginal" cost known as long-run incremental cost (LRIC).

Marginal cost, to the economist, is the cost of producing and selling a single additional unit (here a kilowatt and/or a kilowatt-hour) of product. It refers to the cost of the smallest possible incremental unit at a single point in time. Thus, when a price is equal to marginal cost, the consumer who is deciding whether to make a single purchase of an additional unit of the product is essentially comparing what that additional unit is worth to him with what it costs society to

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[1] This may be illustrated by MG&E's existing residential rate (RG–1), as authorized in an interim order issued in this docket on February 13, 1973, which uses the following schedule: Fixed charge (per month), $1.00. Energy charge—First 100 kWh, 3.00¢; next 400 kWh, 2.25¢; next 500 kWh, 2.00¢; next 500 kWh, 2.00¢; over 1500 kWh, 1.64¢.

[2] See Caywood, *Electric Utility Rate Economics* 72. See also the testimony of Charles Fraizer at Tr. 2142.

produce it. However, this concept of the cost of a *single* incremental unit is not readily applicable to the electric utility industry, where additions to plant are capable of producing *more* than a single unit of output, and on a *continuing* basis. Consequently, in this area it is better to consider incremental costs which refer to discrete blocks of additional production, and to look at these costs over the long-run, rather than the short-run, period.

Thus, the long-run incremental cost is the cost associated with meeting additional blocks of demand for electric power on a continuing basis. It includes not only the immediate or short-run out-of-pocket expenses of taking on "new business," but also the annualized cost of capacity additions necessitated by the new business.

An electric rate design based on LRIC, then, will insure that those uses placing the greatest demands on the system will pay the true costs of such usage —including the costs of new generating capacity. Such a design would give the proper "signals" to customers—that the more you use, the more costly it is to you and to society—and, to the extent that demand is elastic; it would have a desirable dampening effect on demand growth.

As indicated, the witnesses for the company and EDF were in general agreement on the principles that rates must be cost-based if we are to do equity and achieve the efficient allocation of resources; and that adoption of LRIC as the cornerstone of the rate design would provide the basis for such a result. The only remaining difference on this point lies in the speed with which the parties feel the rates should be brought into line with LRIC.

As might be expected, the rate revisions proposed by the company reflect a more deliberate approach to the shared goals, and the environmental intervenors, while not offering any specific proposals for overall rates, did urge more immediate implementation of several changes (which will be discussed below). As may be seen, our order directs the company to implement many of these objectives forthwith.

2. RATE DESIGN

It is clear from the record that a declining block rate structure is no longer appropriate for this company—and, by implication, for other Wisconsin electric utilities. I have long felt that the promotional aspects of such a structure are wholly unjustifiable under today's conditions;[3] and the testimony in this case is very persuasive on the point that such rates are uneconomic and are not justified by cost. Today we have taken positive action to flatten the rates and have announced that henceforth declining blocks in any classification will have to be fully cost-justified by the utility. The degree of "flattening" accomplished in the order may be illustrated by comparing those rates for residential service authorized in the company's last rate case[4] with those approved in today's order:

Residential (Rg-1)	1970 rates	New rates Winter	New rates Summer
Fixed charge	$0.75	$1.50	$1.50
First 100 kilowatt-hours	.0285	.0250	.0250
Next 400 kilowatt-hours	.0203	.0220	.0220
Next 500 kilowatt-hours	.0203	.0220	.0220
Next 500 kilowatt-hours	.0156	.0220	.0220
Over 1,500 kilowatt-hours	.0156	.0150	.0220

[3] See, for example, my dissent in *Re: Wisconsin Electric Power Co.* (1971), 56 PSCW 552 at 574: ". . . we are fast approaching a time when hard decisions will have to be made concerning our increasing use of electricity and the demands such use makes on our mineral resources and our entire natural environment. While our action in one particular rate case will not appreciably affect society's demand for electricity, I do feel that the aplicant's rate schedule should be designed to impose a larger overall percentage increase as the usage increases—in all service classifications. By so ordering, we would be taking the necessary first step toward reversing 'promotional' rate structures which continue to encourage and promote high-volume consumption of electricity."

[4] *Re: Madison Gas & Electric Co.* (1970), 55 PSCW 666. It may be seen that the increases are much more pronounced (up to 40%) in the "tail" blocks than in the early blocks (which range from a slight reduction to a modest increase). When the new rates are compared with the existing rates as authorized in the 1973 interim order in this docket (which applied an across-the-board percentage increase to the 1970 rates) the results, in terms of percentage increases (or decreases) by block are roughly the same. The fixed charges are, of course, increased significantly, and these changes are discussed in some detail in a later section of this opinion.

It may be seen that the flat rates are dependent upon the establishment of a fixed charge adequate to more nearly cover the fixed "customer costs"—those costs incurred to serve a customer even if he uses no electricity at all. These are the costs incurred in reading meters, billing, and certain distribution and service line costs, and they vary with the number of customers, rather than with the electricity produced or required. Here, as is usually the case, it is clear that the company's fixed charges do not come close to recouping all of these costs in the various classifications.[5] The company does not wish to "jolt" its customers by making a jump of the magnitude necessary to cover all of the costs, and while we recognize the validity of this position, we have raised the company's proposed fixed charges in all classifications; and the order gives notice of our intention to bring these charges more fully into line with the actual costs as rapidly as possible.[6]

There is a rather glaring departure from "flat" rate design in the winter residential rate authorized in this order, where the end block is 7/10 of a cent lower than the preceding blocks. This block obviously covers electric space heating—a predominantly off-peak load—and one company witness described the rate as "somewhat stimulative of . . . demand for electric heating, particularly in apartments."[7] There are many unanswered questions in this area, and while I strongly support the philosophy of peak-load pricing, I remain unconvinced that rates should be designed to promote electric space heating. Unfortunately, there is precious little evidence in this record on the subject, and we will have to await a more complete exposition of the subject in a subsequent case.[8]

3. PEAK LOAD PRICING

There is general agreement among the economic witnesses that if a customer adds to the system peak he should be required to pay the cost associated with that demand. Clearly, it is far more costly to serve loads that coincide with the system peak. Not only is capacity built to serve that load, but it is also necessary to rely on the less efficient units for on-peak generation. Obviously, to the extent that capacity is built, but utilized only briefly, the economic penalty to the system is a heavy one.

The essential benefit of a peak-responsibility pricing scheme is that it flattens out the load curve, and tends to discourage the need for investment in additional capacity. Indeed, one of the company's expert witnesses testified that load research studies revealed that MG&E's investments in production, transmission and distribution facilities relate directly to summer peak coincident demands.[9] Thus, the higher summer rates authorized in today's order will put the rate where the growth is—since the summer air conditioning load determines the system peak (and since it is the system peak that largely determines the need for construction of new generating facilities).

EDF argues, however, that while the summer-winter differential is an appropriate first step, the ideal peak-responsibility rate design should be responsive to daily, rather than seasonal, peaks. There can be, for example, a peak period of use in the summer *or* winter, and whenever that peak occurs a higher price

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[5] Fixed customer costs in the existing residential schedule, for example, are $1.00 per month, and there is evidence to indicate that the actual cost is approximately $4.00 per month. Tr. 1559–60; 2157; 2774.

[6] While it has been argued in other parts of the country that higher fixed charges (however cost-justified they may be) might impact on small, low-income users, the New York Commission recently observed that:

"The minimum bill user is not the small user of electric power as that term is commonly understood (low income or otherwise). The amount of consumption covered by the bill is so small that the class is virtually limited to nonusers of electric power—persons away on vacation or maintaining a power connection for contingency purposes. There is no reason why this class should not bear more of the costs associated with maintaining an electric connection (such 'customer costs' as service lines, meter reading, accounting and billing)." *Re: Consolidated Edison Co. of New York* (NY PSC Opinion No. 72–6) at 46–47.

[7] Dr. Charles Frazier, Tr. 2171–72.

[8] The record does contain some inconclusive discussion of the relative energy efficiency of electric, gas and oil heat; and some speculation that MG&E's present electric heat saturation rate of 2½% might increase. See Tr. 2767–71, 2795–96. I remain fearful of the "spill-over" and "seesaw peak" possibilities of space heating promotion, since it is, all things considered, an encouragement of increased per customer usage—and may present the danger of additional on-peak (e.g. air conditioning) usage as well as the ultimate chance of shifting the peak back to the wintertime.

[9] Tr. 1684.

would seem to be warranted. Time-of-day pricing, then, is a logical extension of the general theory of peak responsibility on which we have based summer-winter rate differentials in this and several other recent cases. Time-of-day pricing is also consistent with the purposes underlying our adoption of long-run incremental cost as the "touchstone" of electric rate design—that is, a dampening of the growth in peak demand and an improvement in load factor. It is clear that these ends would be furthered by giving customers the option to reduce the cost of their usage by changing the time of that usage. Each discrete type of service for example, on-peak as opposed to off-peak) has its own LRIC, and it is important to reflect those differences in rates, for rates are the price signals which guide consumer responses. It is eminently desirable to induce customers to minimize the costs which they impose on the utility—and on society—and thus it is important that rates be designed to afford that inducement.

Peak-load pricing, because it tracks costs closely, should also operate to stabilize the utility's earnings, and thus mitigate to some degree the serious earnings attrition that has plagued utilities throughout recent inflationary periods. It is also clearly proper to require increased revenue contributions from those who are imposing increased revenue contributions from those who are imposing increased burdens on the system through increased usage (and increased demand).

Time-of-day pricing is nothing new in some industrial electric rate classifications in the United States. As an across-the-board pricing philosophy, however, it appears to be, as one MG&E witness stated, an "intriguing idea,"[10] rather than a reality. Such rate systems have been in use in Europe for many years. In 1957, Electricite'de France, the nationalized French electric utility, adopted its "green tariff," which was basically an industrial rate with charges varying with time of day and season of the year.[11] The rate levels were based on marginal costs, and when the tariff went into effect the utility estimated that it would result in a 5% reduction in use of electricity at peak. The projections were met, and in 1965 the concept was extended to residential rate classifications.[12]

Time-of-day pricing, of necessity, involves time-of-day customer metering, and the record reveals a wide divergence of opinion on the economic feasibility of such a metering program—particularly in the residential area. Because the idea shows such promise, however, we have directed the company, in cooperation with other Wisconsin utilities, to embark upon an immediate experimental program to determine the applicability and feasibility of a full peak-responsibility pricing system. As the order indicates, such metering is more readily available in some commercial and industrial classifications, and we would expect some immediate efforts by the company to implement time-of-day principles where present technology and economics permit.

4. ELASTICITY OF DEMAND

The record is quite clear on the importance of estimating the elasticity—or price-sensitivity—of demand.[13] Such estimates are important, for example, in properly assigning revenue responsibility in a situation of revenue excess or shortfall, and, as Dr. Stelzer testified, in the ability to "load uninternalized costs onto the most demand-elastic uses."[14] I agree also with Dr. Stelzer's comment that ratemakers (which term, I assume, is intended to include regulators) should know enough about demand elasticities to be able to choose consciously between running the risk of over-stimulation or undue discouragement of usage.[15]

While the estimates offered in this proceeding are very general—and wide-ranging—all of the expert witnesses appear to agree that the elasticity of de-

[10] Tr. 2792.

[11] Clemens, "Marginal Cost Pricing: A Comparison of French and American Industrial Power Rates" *Land Economics*, October 1963, p. 391.

[12] Epstein, "A Proposal to Modernize Electricity Tariffs," *Public Utilities Fortnightly*, August 30, 1973, pp. 28–29. See also Caille, "Marginal Cost Pricing in a Random Future As Applied to the Tariff for Electrical Energy by Electricite de France," *Essays on Public Utility Pricing and Regulation* (Trebbing, Ed.), p. 99.

[13] Tr. 1579.

[14] See Tr. 1562 *et seq.*, 1590, 1794, 1862–63, 1953–54.

[15] Tr. 1567–68.

mand for electricity is greater than zero.[16] It would seem to me that such studies should be an essential part of any rate case, and although the order does not so state, I would hope that a much fuller inquiry into the price elasticity of demand can be undertaken in the very near future.

CONCLUSION

We truly have come a long way in this proceeding. When questions of rate design were first raised, it somehow became known as an "inverted rate" case, and judging from my own mail (and telephone calls) from countless industries in Wisconsin and all over the country, together with press releases from various business and commercial associations, we would certainly be witness to an economic apocalypse if we were to entertain any such proposal. Interestingly enough, the environmental intervenors never really advanced such a proposal, and although the idea of dampening demand growth by increasing the tail blocks in various rate classifications was discussed by several witnesses (and the concept is, I feel, implicit in our move to flat rates) this never was an "inverted rate" case. It was rather a long-overdue and well-presented inquiry into the economic (and social) validity of traditional methods of electric rate design.

Throughout the often frustrating course of these proceedings, it became clear to me that the traditional rate case with its quasi-judicial hearing format (and the hearings in this case were more "quasi" than "judicial," I'm afraid) is a particularly inappropriate forum in which to consider many of the broad policy questions of energy pricing.[17] Not only do many of the issues transcend the operations of a single utility—or even a single industry—but the length of time involved in their consideration (two years in this case) imposes severe burdens on an already overburdened Commission staff—to say nothing about the problems of "regulatory lag."

The problems, then, are institutional as well as substantive, and while we have gone about as far as we can (in the context of this case) in ordering changes in the policy and practice of electric rate design—and have also declared our intention to move still further in subsequent cases—there remains a host of industry-wide (and inter-industry) problems which will have to be addressed by government, the public and the involved industries if we are to remain in control of our energy future.

WILLIAM F. EICH, *Chairman.*

RICHARD D. CUDAHY, COMMISSIONER, CONCURRING: 2–U–7423

THE MERITS

Our decision in this vintage proceeding marks a new and constructive departure in the establishment of rates—one which gives adequate emphasis to the formulation of the prices themselves as distinguished from related aggregates such as revenue requirement or return. This is one of the most challenging and significant cases with which I expect to be confronted during my tenure in office.

Traditionally, revenue requirement (and return) have been for obvious reasons the most critical determinations from the viewpoint of the utility, and state public service commissions have seen their function as providing appropriate limitations upon these aggregates with only incidental attention to the details of distribution of revenue requirement among customers. The principal exception to this general tendency has been a concern by commissions to protect the interests of residential customers as a class.[1]

The instant case in its later phases, however, primarily concerns the structure or design of prices and the relationship of such structure to demand, to the efficient allocation of resources, to wasteful use of resources, to conservation, to

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16 This concept, sometimes phrased in terms of "rejection of the null hypothesis," may be translated to mean "all we know is that it is not inelastic." I suppose economists are equally mystified by legal maxims.

17 Similar views were expressed by Dr. Cichetti at Tr. 2057–59. See also Professor Bonbright's comment to the same end in Bonbright, *Principles of Utility Rates* at 287–88, n. 1.

1 Bonbright, *Principles of Utility Rates*, p. 287–288, fn. 1.

environmental protection, to revenue erosion and also to more conventional (albeit vital) concerns such as revenue requirement. It has been a longstanding dilemma that the ratemaker must choose perforce between the apparently conflicting demands of revenue requirement (based on aggregate historical costs) and rate design (based on a variety of marginal costs).[2] In the instant case this inherent discrepancy between revenue requirement needs and marginal costs is apparently resolved by demonstrating a rough arithmetic equivalence between revenues expected to be generated by rates based on marginal costs and revenues required to provide an adequate return to the enterprise. We may only hope that, in addition to being fortuitous, this equivalence is well-founded.

In any event this equivalence eliminates the need *in this case* for making appropriate elasticity measurements to determine which customers served on which sectors of the rates should accept the benefit or the burden, as the case may be, of the difference between revenues based on marginal costs and revenue requirement. But, if such need existed, the "inverse elasticity rule" espoused by Dr. Stelzer in this proceeding prescribes a method based on elasticity determinations for appropriately distributing in the inelastic sectors of the rates the difference between revenue requirement and revenue derived from rates set at marginal costs.[3] Such an approach is perhaps more practicable than the use of taxes or subsidies to resolve disparities between revenues based on marginal costs and revenue requirement based on average experienced costs and designed to provide an adequate return.[4]

The evidence adduced in the instant case, as previously indicated, tends to show that revenue derived from rates set at marginal costs is roughly equivalent to revenue requirement based on experienced costs and experienced interest rates. One might argue the validity of certain broad conclusions to be drawn from this relationship: (1) electric power (or at least Madison Gas and Electric Company) is neither an "increasing" nor a "decreasing" cost industry, (2) economies of scale in the generation, transmission and distribution of electricity have been exhausted.[5] It may also be possible to conclude that, if (1) and (2) apply, a flat rate structure should be generally appropriate since increasing usage has no significant impact on cost per unit of usage.

I believe, however, that there may be several infirmities in this course of analysis, even though the ultimate conclusion may be defensible. For one thing, to determine whether costs are "increasing" or "decreasing" one should compare long-run marginal or incremental costs with average costs based on *current* price and interest rate levels—not average *historical* or *experienced* costs. Any other approach would seem to distort the "pure" effects of scale by injecting the problem of inflation. The fact that marginal cost is equal to average *experienced* cost would seem to indicate that marginal cost *may* be somewhat *less* than average cost measured at *current* price levels. This is to say that, to some degree, a "decreasing" cost situation may still exist. This is not surprising since common sense suggests that, although economies of scale may well be exhausted in generation (although not necessarily for Madison Gas and Electric Company), they are probably still present to a degree in transmission and distribution.[6]

Our order, I believe properly, approves long-run incremental cost (LRIC) as the most appropriate touchstone of ratemaking, and, in this case at least, we have accepted LRIC subject to the two traditional prescriptions that (1) it be calculated in current constant (deflated) dollars and that (2) it assume a given state of technology. The latter condition is satisfied by the confinement of the cost study to known and planned facilities and the former by adjustment of future costs to eliminate the effects of assumed general inflation. We thus

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[2] Id. at 386.

[3] Tr. 1537–1541.

[4] See Bonbright, n. 1, *supra* at 387.

[5] Thus Dr. Stelzer testified in response to a question by the writer at Tr. 2090–2091:

"Commissioner Cudahy: Is it the fact that apparently LRIC [long-run incremental costs], in the case of Madison Gas and Electric Company, are equal to average costs, that overall system-wide the economies to scale have been exhausted?

"The witness [Dr. Stelzer]: At the moment, and in aggregate, we seem to be in a situation of constant cost where there may be static economies of scale at the point in time where a bigger unit is more efficient than a smaller unit, but in which the total effect of addition to capacity is not going to be the lower cost.

"Now that may change later, but it seems to be where we are now with that system."

[6] See Kahn, *The Economics of Regulation*, pp. 123–158.

conceive of LRIC in the static (and academically approved) sense as isolating cost relationships related solely to *scale*.[7] This concept has been criticized by knowledgeable economists as of questionable practical value in electric rate-making principally because its static reference is allegedly divorced from current dynamic reality, where both prices and technology are in constant ferment.[8] Nonetheless we are inclined to believe that LRIC represents at root a most important concept which should not be rejected merely because it may change frequently in the future. The same difficulty exists with respect to other cost methods.

As indicated above and in our order, the economic evidence in the instant proceeding offers no definitive, universal and unarguable prescription of rate form—whether it be flat, declining-block or "inverted." But this evidence, coupled with factors to be set forth, strongly suggests the flat rate as the preferred point of departure especially for construction of residential rates.

In my view the most plausible general basis for "inverted" rates would be the substantial incorporation of uninternalized social costs into marginal costs. Uninternalized social costs might well contribute to diseconomies of scale (since such costs may tend to rise disproportionately with size). And diseconomies of scale, presumably, would have their analogues in "inverted" rates. In any event inclusion of uninternalized social costs (not *incurred* on the books of the utility) would probably produce rates yielding more than average *incurred* costs. The excess revenue yield could arguably be compensated by *increases* in later, strongly elastic, blocks (where usage would be disproportionately reduced) and possible *decreases* in early inelastic blocks, resulting in "inverted" rates.[8a] But as our order in this case suggests, direct control of, or taxes on, industrial emissions generally may be a more efficient means of achieving the vital goal of internalizing social costs than the possibly distorting application of "inverted" rates to electric power. Another possible basis for inverted rates, it is sometimes suggested, is an alleged high forced outage rate of large generating units.[9] This condition, however, even if consistently demonstrated, would be a better argument for smaller plants than for "inverted" rates. In general, the unpredictable effect of "inverted" rates upon usage, revenues, economic activity and a variety of other considerations make their *general* adoption undesirable, based on this record. This conclusion is underlined by recent rate level problems arising from declining usage in relation to high and rising fixed costs.[10]

As to the general issue of choice between flat and declining block rates, the economic evidence (insofar as it points to a definite movement away from "decreasing" costs) offers substantial support to the concept of flat rates as a starting point, bearing some presumption of reasonableness. But I am persuaded that each class and sub-class of customers must also be analyzed on its own merits (with particular emphasis on contribution to annual—or, if applicable, seasonal—peaks). For purposes of efficient blocking the essential question is whether additional usage results in lower or higher per kilowatt-hour costs. As a simplistic matter (and this is one of the arguments advanced for declining-block rates), it would appear that spreading additional usage over the same fixed costs would produce lower average costs. An important facet of this concept is illustrated by current utility distress over loss of revenues due to conservation. This line of reasoning seems to be correct in the case of "customer" costs, but beyond that it reflects only *short-run* considerations and is valid *in the long run* only if contribution to annual or seasonal (cost-causing) peaks is less than directly proportional to the corresponding increase in usage.

In the case of the summer residential rate we have assumed that increased usage (containing air conditioning) contributes at least proportionately to the annual (temperature-sensitive) peak. We have thus, after recovery of customer costs (in the fixed charge and in the first block), constructed a flat rate. No doubt this approach incorporates only a rough tracking of costs through the

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[7] In other words we are talking about costs in the long run which are *caused by* increases in output. See Tr. 1543–1548.

[8] See Diana E. Sander, *Rate Structure Concepts—A Comment*, pp. 16–21. Mrs. Sander is the Principal Economist, New York State Department of Public Service.

[8a] Cf. Tr. 1576–1580.

[9] Cf. Tr. 258–259; 880–882.

[10] See *Re: Niagara Mohawk Power Company*, Opinion No. 74–5, Case 26402. (N.Y. Pub. Serv. Comm., Feb. 5, 1974) at p. 31.

rate blocks. But with current metering techniques, these seem to be the best cost approximations which can be achieved. I must emphasize that *customer-related* costs, which are approximately equal for each customer of the class and which *do* result in higher per kilowatt-hour costs for smaller customers, must be treated differently than *demand-related* costs, which are presumptively different for each customer. In addition, in my view and almost by definition the mere fact of hooking up creates an ascertainable "customer" cost, while the level of "demand" costs for a particular customer is usually ascertained only by an experienced requirement for delivered power on system peak. In summer, demand-related costs tend to be greater for larger-use customers, whose end-block use is largely air conditioning. It is not unreasonable, therefore, in summer to assume growth in coincident peak demand at least proportionate to growth in usage by residential customers and hence to prescribe a flat rate. Such a presumption is always subject to rebuttal by empirical evidence not presented in this case.

We have in the instant order adopted a summer-winter rate differential generally in accordance with applicant's proposal (although we have increased the differential). One of the side-effects of assessing relatively heavy peak responsibility in the flat summer residential rate is to accept a sharply declining residential winter rate with an end-block charge (principally to accommodate electric space heating) of only 1.5¢ per kilowatt-hour. How well this rate tracks LRIC through the blocks is open to question, but it seems clear that, if an annual peak responsibility theory is to lead to relatively high, relatively flat rates in summer, one must be prepared to accept relatively cheap (but, of course, compensatory) winter end-block charges. This may stimulate the installation and use of electric resistance heating, and I am well aware of the various objections to this development, but the peak responsibility theory compels the characteristics of the end-block charge. Nonetheless, one must be particularly sensitive to the possibility of building a new winter peak based on the vast untapped potential of the electric space heating market to replace the currently onerous air conditioning peak.

It may be important to consider such objections to electric space heating as "spillover effect,"[11] allegedly low thermal efficiency, conflict with use of solar energy, "spiking" peaks and so. Perhaps inconsistent with views I have expressed in earlier opinions, I am now inclined to believe that policies, if there are to be any, in the space heating area should *not* be pursued primarily through what may amount to manipulation of the rates but rather, if necessary, through some direct regulatory action.[12] If we are to opt firmly for a relatively pure application of annual peak responsibility (where the annual peak is well-defined), we are compelled at the least to a sharp summer-winter differential with low winter end-block rates. If, as some would contend, these low winter rates, by stimulating the presumably elastic demand for electric space heating, cause new peaking capacity costs, then we must reexamine the appropriate application of the theory of annual peak responsibility. The Commission should consider conducting an inquiry to determine whether, as some suggest, stimulation of electric space heating will in fact produce new daily, weekly or monthly demands causing costs related to construction or use of non-base load capacity.

The changes made in this proceeding by applicant and by the Commission in commercial and industrial rates accord with the general tendencies of LRIC. We have, perhaps, gone far enough, in view of the general acceptance of the applicable principles and of equitable considerations, in making changes going beyond those already proposed by applicant. This may be particularly true in view of the relative dearth of typical industrial load on applicant's system. But the task of weighting demand charges more heavily in accordance with LRIC should go forward, together with an indicated movement toward flattening energy charges.[13] But, in any event, the problems of applying the principles of LRIC to the industrial and commercial classes as well as to the residential class, without more precise methods of assignment of peak responsibility, are clear.

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[11] I.e. The alleged tendency of other electric appliances to be added with electric space heating.

[12] Cf. Sander, n. 8, *supra* at pp. 84–85; Brief of Intervenor, Wisconsin's Environmental Decade, Inc., in *Re: Wisconsin Electric Power Company*, Docket Nos. 2–U–7908, 2–U–7915 (June 24, 1974).

[13] Tr. 1008, 2196.

Lack of precision in assignment of peak responsibility is the basic reason for exploring peak load pricing, as exemplified in time-differential rates—both on a seasonal and on a time-of-day basis. The summer-winter differential is a form of such pricing, albeit a relatively crude one and one which so far has no demonstrated history of restraining summer peaks. Time-of-day differentials, of course, should be more effective in shifting uses off peak. Dirty clothes may be washed and dried in the evening, but it would be difficult to store them up to be processed until the following winter. What apparently is most needed is a method for generously rewarding off-peak usage and for rigorously penalizing on-peak usage. Assuming significant elasticity of demand this would (1) improve load factor and (2) limit growth of new capacity. From every point of view the improvement of annual and seasonal load factors (by means going beyond mere building of off-peak load) is crucial to improving the frayed economics of the electric power industry.

Time-differential pricing aimed at fuller and more accurate assessment of costs against peak loads must be explored in controlled experiments and applied *promptly* in areas where it seems economic. Perhaps the most promising area with which to begin would be the large industrial class where recording demand meters are already in operation and can be used directly for time-of-day metering. Investigation may demonstrate that significant amounts of industrial usage may be moved off peak by careful scheduling of various industrial processes. In a number of cases this type of scheduling may prove quite economic when full capacity costs begin to be assessed against peak users.

As to generating and transmission capacity cost, it may be appropriate, for example, to assess full *peaking* capacity costs (as well as appropriate energy costs) against electricity used during periods when experience indicates the system may be operating within 90% of peak (*e.g.* between 10 A.M. and 9 P.M. on weekdays in summer). Another rate covering the difference between base load and peaking unit capacity cost per kilowatt (as well as the appropriate difference in energy costs) may be assigned to periods when the system is apt to be operating between 75% and 90% of peak (*e.g.* 7–10 A.M. and 9–11 P.M. on working days in summer, 7 A.M.–11 P.M. on weekends in summer, and 7 A.M.–9 P.M. in winter). It seems appropriate to assign *peaking plant* capacity and energy costs at the peak since this is the type of capacity which would be built to serve the peak alone, with base load capacity being provided for more continuous demands.

With respect to peak load pricing, in Great Britain the Electricity Council conducted an experiment with residential customers between 1967 and 1972 testing three tariff structures: (1) a seasonal differential tariff which provided for a unit price of about 150% of the unrestricted follow-on ("standard") rate of the ordinary domestic tariff during the "peak months" of December, January and February and for a "summer" price of about 70% of standard; (2) a seasonal time-of-day (STD) tariff with a price of 300% of standard, applied between 8 A.M. and 1 P.M. and between 4:30 P.M. and 7:30 P.M. of winter working days, a price of 40% of standard applied between 11 P.M. and 7 A.M. of every day and an intermediate price of some 80% of standard applied at other times; and (3) a "load rate" wherein a "subscribed" load was served at a unit price of about 60% of standard with excess consumption charged at prices of about 100%-200% of standard.[14]

Special metering was required for all three rates—with a three register meter for the STD tariff. Incentive payments were made to customers participating in the experiment (who had been recruited on a basis which was non-optional as to the rate offered) thus, among other things, tending to protect customers against losses resulting from operation of the experimental rates.[15]

There was some gain in total annual consumption under all three of the experimental tariffs in comparison with the control group. Average daytime load factors, however, increased significantly in the case of the time-differential rates, with a load factor improvement of 10% associated with the seasonal experimental rate. A gain of about 7% was associated with the seasonal time-of-day rate. Also a price-induced *seasonal* shift in annual usage of about 2.1% took place with respect to the seasonal experimental rate. The STD tariff was effec-

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[14] See Load and Market Report No. 121, "Domestic Tariffs Experiment" (The Electricity Council, Great Britain, November 1973).

[15] Id. at pp. 3–7.

tive in shifting consumption away from the peak hours while the seasonal rate, *in conjunction with restricted hour rates*, was most effective in terms of improvements in daytime load factor. Restricted-hour rates (which apparently had a marked effect on the seasonal rate experiment) were employed in connection with interruptible service for certain applications, such as space and water heating, where electric supply was disconnected at peak periods.[16]

Consumer response to the experiment was good in that all consumers taking part in it—even those on the more punitive high rates of certain split samples for pricing—thought that their tariffs were worth continuing and would recommend them to friends. None of the experimental tariffs apparently inhibited the acquisition of appliances, but the installation of storage electric heating was stimulated by time-differential rates and direct-acting heating by the load rate.[17]

But cost-benefit analysis conducted with respect to each branch of the experiment showed negative results because of the excessive costs of metering in relation to economic benefits achieved. This points up the need for economical mass-produced metering devices if peak load pricing is to be effectively pursued in areas other than those in which recording demand meters are already used.[18]

I cite the Domestic Tariffs Experiment of the Electricity Council at such length only because it illustrates the sort of research to be undertaken, the way in which it may have to be structured, the questions which probably have to be answered and the difficulties (as well as, sometimes, the surprising ease) of getting helpful answers. The French experience might also be noted since Electricite' de France has employed time-differential pricing (incorporating sharp differences in rates) for bulk and industrial customers (where metering is not a major problem) for a number of years.[19] There is a considerable body of European experiment and experience with time-differential and load-rate pricing.[20]

Electricity has become a very much more precious commodity than it was previously believed to be. Conservation and a strict accounting of costs—both pecuniary and environmental—have become the order of the day. For these reasons primarily it seems clearly justified to explore much more exacting systems of cost determination than were previously thought appropriate. It is, perhaps, belaboring the obvious to recite that, because electricity cannot be stored, the cost characteristics of kilowatt-hours delivered at different hours of the day and during different seasons of the year may be quite different. These differences result from the varying casual relationships of the demand for these units of energy to the costs of capacity.

We can only achieve so much (some of it hopefully good) by flattening rates, or even "inverting" them and standing traditional practices *within existing structures* on their head. Only, I think, by seeking to change the system to provide rate incentives or penalties, as the case may be, to those who can and will change their usage to improve the overall economics and social impacts of the system can we make really significant progress. Some utilities already *advertise* the virtue of off-peak use (of clothes washers, driers, etc.); our concern should be to see that the "virtuous" are rewarded in the rate (and the "unvirtuous" penalized). There must be experiment, but prompt action based even on possibly unperfected experiment may be required. This is eminently the case in the industrial sector where peak load pricing may be accommodated within existing metering systems. The hour is late and the system cries out for better methods of control. The emphasis should no longer be entirely on an adequate supply of electricity whenever demanded, but also on a structuring of demand to call forth a more orderly and economic supply.

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[16] Id. at pp. 9–10.
[17] Id. at pp. 11–12.
[18] Id. at pp. 12–18.
[19] The French "Tarif Vert" was put into effect in 1956 (for bulk and industrial sales). Under it demand charges (as well as, to an appropriate extent, energy charges) are based on system peak contribution. Demand charges to industrial customers in the Paris region involve discounts ranging from 0% in the winter peak months to 98% in the summer empty months. See Kahn, *supra*, n. 6, Vol. 1, p. 97, fn. 23; Meek, *An Application of Marginal Cost Pricing: the "Green Tariff" in Theory and Practice,"* Part I, Journal Ind. Econ. (July 1963), XI: 217–236.
[20] See Turvey, *Peak-Load Pricing*, 76 Jour. of Polit. Econ., No. 1, pp. 101–113. (Jan./Feb. 1968).

I should prefer, with respect to our declination to require an environmental impact statement to be prepared and circulated in the instant proceeding (pursuant to Sec. 1.11, Wis. Stats.), to rely additionally or alternatively on the doctrine of *Scenic Hudson Preservation Conf.* v. *Federal Power Com'n.*[21] in that the hearings conducted herein reflect the "systematic, interdisciplinary approach" associated with an environmental statement and, in effect, constitute an adequate environmental inquiry.[22]

There also is a degree of circularity to the argument that, since the Commission liberally admitted environmental evidence in this proceeding and considered environmental factors, it is therefore required to prepare an environmental impact statement pursuant to Sec. 1.11, Wis. Stats. Several well-reasoned cases have held that, even though the *specific procedure* of preparing an environmental impact statement is not required by law, evidence of alleged environmental effects, impacts and relationships may be freely admitted as going to the general question of the public interest.[23] It would seem to me to be harmful to environmental goals to, in effect, penalize the free admission of environmental evidence and free consideration of environmental factors by determining that such open policies lead to the additional and essentially duplicative burden of an environmental statement.

RICHARD D. CUDAHY, *Commissioner.*

ARTHUR L. PADRUTT, COMMISSIONER, DISSENTING: 2–U–7423

The testimony and debate presented in this case by the learned economists who participated is strongly reminiscent of the disputes of an earlier age when theologians differed concerning the number of angels who could occupy the head of a pin. 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. In the meanwhile, those of us not so well endowed, bearing the burden of formulating a viable and practical rate design, were left to slog painfully through the foothills below.

From the outset, there has been something of an unrealistic aura—an Alice-in-Wonderland flavor to this case. As a test of the validity of the declining block rate structure or conversely as affording a good testing area for inverted rates, flattened rates, summer-winter differentials and the rest, MG&E is about as unlikely a candidate as conceivably could have been chosen. Madison Gas and Electric Company is a completely atypical public utility. It is small. Its service area is compact, with a high customer density. It has a minute industrial load and very little rural load. To consider it comparable to the norm of electric utility operations generally is grossly misleading. To lay down principles of rate design applicable to all other electric utilities operating in this state, as this order purports to do, is beyond the scope of this Commission's jurisdiction.

The facts and circumstances of this case are unique to MG&E and its peculiar operating conditions cannot be attributed to any other utility. The evidence adduced in this case must be applied only to this applicant. It furnishes an insufficient base for the formulation of sound public policy with respect to other utilities.

In any discussion of the principles and practices of rate design the cardinal principle, completely overlooked in the order, is ease of administration. This tenet also appears to have been lost sight of in the formulation of the rate structure endorsed herein.

Rates should reflect all tangible, actual, measurable costs of providing the service. To the extent that marginal costs include something other than an actual tangible, measurable cost of production, I am in disagreement with the conclusions of the order. By extension then, I find myself in disagreement with

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[21] 453 F. 2d 463 (2 Cir., 1971).
[22] 453 F. 2d 463, 481.
[23] See, e.g., *Complaint of the Natural Resources Defense Council*, 2 E.R.C. 1808 (C.A.B., 1971).

the long run incremental cost (LRIC) concept as a basis for rate design. Granted that the concept possesses certain virtues which recommend it, it is nevertheless possessed of certain disabilities which are of sufficient concern, in my judgment, to preclude its adoption.

First of these concerns is that LRIC introduces something other than known measurable costs whose ascertainment is consequently dependent upon someone's judgment. "Whose judgment?", one may inquire and thus concomitantly raise the question of the subjectivity of the judgment. One suspects the answer would vary with the judgment and given the opinion of a hundred different experts, one would have a hundred different answers.

In some respects I am reminded of the dispute concerning original-cost versus reproduction-cost-new or fair value as an appropriate means of determining rate base. Given the Wisconsin experience, I prefer the solidity afforded by actual costs which obviate any need for judgmental reliance.

A second concern is grounded in the fact that if given full recognition, LRIC will invariably produce revenues considerably in excess of revenue requirements. Probabilities seem to be that LRIC would prove to be equivalent to revenue requirements about once in a million times. That the one study provided in this case indicates an equivalent result is simply incredible. This leads one to suspect that, given the answer required, LRIC can be calculated to produce that result. Obviously, this manipulative facility provides too infirm a base to support a sound principle of ratemaking. The avoidance of discrimination is a prime mandate of the statute and another cardinal precept of rate design. So infirm a process carries with it the inherent danger of discrimination by design or simply through inadvertance.

When we consider peak load pricing we at least approach a subject more capable of ready understanding. Its theory is simple. Increase the price of energy at peak load periods to a point which encourages the customer to defer his use to another, less costly time. In other words, encourage the housewife, (for an oversimplified example) to turn the dishwasher on at 10 P.M. instead of 7 P.M. where the "dishwasher peak" presently exists. In theory, this is excellent, but it should be very obvious, that if in practice the gambit is successful, the ultimate result wipes out the 7 P.M. peak and builds a new one at 10 P.M. This serves to demonstrate the basic fallacy involved in peak load pricing. An additional problem is encountered with respect to peak load pricing in its more refined version, namely time of day metering. In this application, a most expensive investment in metering equipment would add a substantial sum to customer costs for the dubious benefit of chasing peaks around the clock.

Much testimony (one should say "discussion") was devoted to the subject of the "elasticity of demand" for electricity. In other words, does a high price discourage its use? In fact the answer to this question underlies the entire approach to the problems posed by this case as well as the result reached. Some discussion is thus warranted. It is elsewhere indicated, concerning a study of the subject matter that "the elasticity of demand for electricity is greater than zero". This does appear to be practically unassailable as a conclusion. I suggest that both a rubber band and a piano wire are elastic. I suspect that the elasticity of demand for electricity more nearly approximates that of the piano wire than that of the rubber band. Electricity has become so integral a part of our daily life, so taken for granted, so necessary to the ordinary comfort and convenience of us all, that its use will not easily be given up or curtailed.

An adequate and reliable supply of energy has become a basic necessity underlying our economy, our industry, our productivity as a society, our whole way of life. Many witnesses from the industrial and commercial world testified to their need for this vital commodity and their fear that changes in rate concepts would do violence to their particular establishment. The health of the industrial and commercial enterprises of Wisconsin is a matter of concern to all whose livlihood is dependent on their well-being, and great care must be exercised by the ratemaker to avoid disruption of their basic economy. This is not to suggest that the result in this case produces any such disruptive force, but it could open the door, by extension of the principles enunciated herein, to such a result in the future. I would prefer to keep the door closed.

Much more could be said about the various aspects of this case which must be omitted here. However, it is not inappropriate to remind ourselves of a peculiar characteristic of electricity as a commodity which lies at the heart of the problem. It is incapable of being stored. It can not be produced, packaged and placed on the shelf awaiting the most propitious moment for consumption as is the case with most other consumer goods. In point of fact its consumption must be precisely coincident with its production. It is this unique and peculiar characteristic which was, through the years, to send utility management and regulators as well, off in vain pursuit of the most favorable load factor and a rate schedule which would ensure it. This fact, often overlooked by today's strident critics of the industry, once again appears to be setting us off in another futile chase after a will-o-the-wisp.

Which leads me to suggest that the traditional, declining block rate structures still have something to recommend them. No one can deny that they are cost-related. We have the benefit of many years of largely satisfactory experience. They treat the customer fairly and through the years have produced revenues sufficient to provide an adequate and reliable supply. It is, or should not be, a matter of surprise that under current conditions of inflation that this pricing system should limp a little. By changing the system we treat a symptom, not the disease. Cure the basic ailment (inflation) and we shall find the need for tampering with the system dissipated. I prefer to rely on this well established rate structure rather than prescribe a method which is based on so much speculative theory. The proposals adopted by this order, open the door to a host of problems I would rather avoid.

One point frequently overlooked in considering the problems of rate design, especially in a period of instability and uncertainty, should be stressed.

It should be emphasized over and over again that in its legislative inception, its administrative application and judicial development, regulatory policy contemplated making available to all who required it as much energy as was reasonably needed, regardless of time of day or season of year, at the lowest possible price consistent with the financial integrity of the utility supplier of the service.

The doctrine, which may be termed the heart and soul of regulation, epitomises the only energy policy we have known. It is still the governing policy today. All of the discussion thus far, concerning energy shortage, nuclear versus fossil fuel, environmental impact, consumerism and all the other involved satellite issues, has not changed this basic policy. The duties, obligations, rights and benefits flowing therefrom remain unchanged.

Reasonably adequate service at reasonable rates, is still the law of the land. In return for its privileged status, its exclusive right to serve, the utility still has the obligation to provide the service to all who demand it. Neither utility management nor regulatory officials are relieved of any of the burdens of this doctrine unless and until appropriate action to do so is taken by state or national policy making bodies.

If we are to embrace new concepts of rate design whose purpose is to thwart these basic policies, I would prefer to await the appropriate legislative mandate. I therefore must register my dissent.

ARTHUR L. PADRUTT, *Commissioner*.

APPENDIX A

APPEARANCES

Madison Gas and Electric Company, Applicant, by John A. Hansen, Attorney, Madison (May 24, September 11, 12, 13, and 14, October 17, 18 and 19, and December 19, 20, and 21, 1972, August 20, 21, 22, 23, and 24, 1973, and January 21 and 22, 1974) and by William A. McNamara, Financial Vice-President, Madison (May 24, September 11, 12, 13, and 14, October 17, 18, and 19, 1972, August 20, 21, 22, 23, and 24, 1973) and by Willard S. Stafford, Attorney, Madison (January 21 and 22, 1974)

In opposition

Roney Sorensen, County Supervisor, Madison (May 24, 1972).

Wisconsin Coin-Op Laundry Association, by Mrs. Lionel G. Moore, Treasurer, Madison (May 24, 1972); Alice M. Schmidt, Madison (May 24, 1972); Mrs. Nancy Loether, Madison (May 24, 1972); Alicia Ashman, Madison (May 24, 1972); Representative Harout O. Sanasarian, Madison (September 11, 1972); and by Paul Zagorski, Administrative Assistant, Madison (September 11,

1972) and by Dennis P. Hanke, Administrative Assistant, Madison (May 24, 1972) ; Richard Ginnold, Supervisor (Appearing for himself), Madison (September 12 and 13, 1972).

City of Madison, by William A. Jansen, Principal Assistant City Attorney, Madison (May 24, September 11, 12, 13, and 14, October 17, 18, and 19, and December 19, 20, and 21, 1972. August 20, 21, 22, 23, and 24, 1973. January 21, 1974).

Wisconsin's Environmental Decade, by Peter Anderson, Public Interest Lobbyist, Madison (May 24 and December 19 and 20, 1972. August 20, 21, 22, 23, and 24, 1973) and by John C. Neess, Rio (September 11, 12, and 13, October 17, 18, and 19, and December 19, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974) and by Melvin I. Goldberg, Attorney, Madison (August 20, 21, 22, 23, and 24, 1973).

Capital Community Citizens, by John C. Neess, Rio (May 24, 1972) and by James A. Olson, Attorney, Madison (September 11, 12, and 13, October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973).

Robert H. Owen, Jr., Madison (December 20, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).

As interest may appear

Environmental Defense Fund, Inc., Capital Community Citizens, by Edward Berlin, Attorney, Washington, D.C. (September 11, 12, and 13, October 17, 18, and 19, and December 19, 20, and 21, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974) ; Scott H. Lang, Attorney, Washington, D.C. (September 11, 12, and 13, 1972) ; David R. Caulkins, Waunakee (May 24 and October 18 and 19, 1972).

Sierra Club–John Muir Chapter, by Sarah Jenkins, Madison (September 11, October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973. January 21, and 22, 1974) (Sometimes in Opposition).

Wisconsin Department of Justice, by Steven M. Schur, Assistant Attorney General, Madison (May 24, 1972) and by Theodore L. Priebe, Assistant Attorney General, Madison (September 11, 1972).

Dane County, by Robert M. Hesslink, Jr., Madison (September 11, 12, 13, and 14, 1972).

Wisconsin Power and Light Company, by Eugene O. Gehl, Attorney, Madison (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973) and by Homer Vick, Secretary & Director of Rates, Madison (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973) and by R. A. Medenwald, Project Analyst, Madison (December 19 and 20, 1972) and by James G. Miller, Rate Engineer, Madison (January 22, 1974).

Lake Superior District Power Co., and Superior Water, Light and Power Co, by Hugh H. Bell, Attorney, Madison (October 17, 18, and 19, 1972).

Wisconsin Public Service Corporation, and Northern States Power Company, by Steven E. Keane, Attorney, Milwaukee (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973) and by Paul M. Barnes, Attorney, Milwaukee (August 20, 21, 22, 23, and 24, 1973).

Wisconsin Electric Power Company, by Robert H. Gorske, Attorney, Milwaukee (October 17, 18, and 19, and December 19 and 20, 1972) and by Edgar R. Watrous, Milwaukee (August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).

Wisconsin Federation of Cooperatives, by Glenn M. Anderson, Executive Secretary, Madison (October 17, 18, and 19 and December 21, 1972).

Dairyland Power Cooperative, by James H. Sherwood, Manager, Information and Marketing, La Crosse (October 17, 18 and 19, 1972).

New Glarus Electric Utility, by R. C. Keppler, President; Harvey A. Ott, Treasurer; Orville Jorenby, Superintendent; New Glarus (October 17, 18 and 19, 1972).

Wisconsin Michigan Power Company, by Karle Naggs, Director of Customer Relations, Appleton (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973).

Wisconsin Manufacturers' Association, by Arvid A. Sather, Attorney, Madison (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).

Madison Metropolitan Sewerage District, by W. J. Landwehr, Chief Engineer and Director, Madison (October 17, 18, and 19, 1972).

Juneau Electric Utilities, by Robert Selchert, Superintendent, Juneau (October 17, 18, and 19, 1972).
Columbus Rural Electric Co-operative, by D. E. Eickelman, Manager, Columbus (October 17, 18, and 19, 1972).
Muscoda Light and Water Commission, and Municipal Wholesale Power Group, by Joseph H. Drone, Superintendent, Muscoda (October 17, 18, and 19, 1972).
Trempealeau Electric Cooperative, by Gordon L. Meistad, General Manager, Arcadia (October 17, 18, and 19, 1972).
Wisconsin Rapids Water Works & Lighting Comm., by Robert F. Dickinson, General Manager, Wisconsin Rapids (October 17, 18, and 19, 1972).
Mercury Marine, Div. Brunswick, by Carl J. Indermuehle, Plant Engineer, Fond du Lac (October 17, 18, and 19, 1972).
American Motors Corporation—Staff, by T. F. Ellis, Manager, Plant Engineering, Detroit (October 17, 18, and 19, 1972).
St. Mary's Hospital Medical Center, by Gerald W. Lefert, Assistant Executive Director, Madison (October 17, 18, and 19, 1972).
Wisconsin Canners & Freezers Association, by Marvin P. Verhulst, Executive Director, Madison (October 17, 18, and 19, 1972).
Ray-O-Vac Division, ESB, Incorporated, by Rolf N. Olsen, Attorney, Madison (October 17, 18, and 19, 1972).
Anne Habel, Madison (October 17, 18, and 19, 1972).
Daily Cardinal, by Jan Laan, Reporter, Vilas Communication Building, University of Wisconsin, Madison (October 17, 18, and 19, 1972).
Allen Bradley Company, by John A. Gasiorowski, Manager, Plant Engineering, Milwaukee (October 17, 18, and 19, 1972).
George A. Hormel & Company, by Ronald L. Scherubel, Attorney, Austin, Minn. (October 17, 18, and 19, 1972).
A. O. Smith Corporation, by Henry O. Allen, Sr., Vice-President, Hartland (October 17, 18, and 19, 1972).
Department of Business Development, State of Wisconsin, by W. C. Kidd, Secretary, Madison (October 17, 18, and 19, 1972).
Wisconsin State Chamber of Commerce, by John D. Winner, Attorney, Madison (October 17, 18, and 19, 1972).
John Deere, Horicon, by A. M. Learman, Public Relations, Horicon (October 17, 18, and 19, 1972).
DEC International (Dairy Equipment Company), by Henrik Moe, Treasurer, Madison (October 17, 18, and 19, 1972).
U.S. Government Veterans Administration, by Vaughn Monahan, Chief Supply Division, V.A. Hospital, Madison (October 17, 18, and 19, 1972).
Oscar Mayer & Company, Inc., by John E. Knight, Attorney, Madison (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973).
Wisconsin Alliance of Cities, Inc., by William H. Beyer, Executive Secretary, Madison (October 17, 18, and 19, 1972).
Wisconsin Hospital Association, by Don S. Rush, Attorney, Madison (October 17, 18, and 19, 1972).
Nordberg—Division of Rex Chainbelt, Inc., by A. D. Spicer, Manager, Plant Engineering, Milwaukee (October 17, 18, and 19, 1972).
Thomas Chemical Company, by Fred L. Thomas, Owner, Madison (October 17, 18, and 19, 1972).
First Wisconsin National Bank of Madison, by Thomsa D. Zilavy, Attorney & Partner, Ross, Stevens, Pick, and Ross, Madison (October 17, 18, and 19, 1972).
United Foundrymen of Wisconsin, by Robert E. Seaborn, Plant Engineer, Falk Corporation, Milwaukee (October 17, 18, and 19, 1972).
Kimberly-Clark Corporation, by Richard R. Nelson, Manager, Utilities Eng ..er, Neenah (October 17, 18, and 19, 1972).
Madison General Hospital, by Terri Potter, Assistant Administrator, Madison (October 17, 18, and 19, 1972).
K. W. Haagensen, Madison (October 17, 18, and 19, 1972).
McGraw-Hill, by Dennis J. Chase, Correspondent, Chicago (October 18 and 19, 1972).
Wisconsin Electric Cooperative Association, by Walter Seaborg, Jr., Management Assistant, Madison (October 18 and 19, 1972) and by M. L. LeBakken, Chief Engineer, Madison (August 20, 21, 22, 23, and 24, 1973).
Rebecca Young, Madison (October 18 and 19, 1972).

Lakehead Pipe Line Company, Inc., by T. J. Gordon, Senior Attorney and Assistant Secretary, Superior (October 18 and 19, 1972).
Cynthia Sampson, Madison (December 19 and 20, 1972).
3M Company (Plants in Prairie du Chien, Wausau, Cumberland and Nekoosa), by Robert R. Wakefield, Elect. Manager, St. Paul, Minn. (October 18 and 19, 1972).
Alrco, Inc., by Joseph M. Cleary, Director Corporate Utilities, Murray Hill, New Jersey, (October 18 and 19, 1972).
Green Bay Metropolitan Sewerage District, by Meyer M. Cohen, Attorney, Green Bay (August 20, 21, 22, 23, and 24, 1973).
Associated Milk Producers, Inc., by Lyman D. McKee, Madison (August 20, 21, 22, 23, and 24, 1973).
Glenn L. Thronson, Dairy Farmer, Blue Mounds (August 20, 21, 22, 23, and 24, 1973).
BASF Wyandotte Corporation, by Robert B. Rodgers, Parsippany, New Jersey (August 20, 21, 22, 23, and 24, 1973).
John Siefert, Franksville (August 21, 1973).
Kathryn I. Derene, Middleton (August 21, 1973).
Michigan Public Service Commission (Peer Group), by Roger F. Fischer, Deputy Chief of Staff, Lansing (August 21, 1973).
Senator Douglas LaFollette, by James E. Schulte, Madison (January 21 and 22, 1974).
Wisconsin Public Service Corporation, by Gary H. Grainger, Electric Rates Supervisor, Green Bay (January 21 and 22, 1974).
Oscar Mayer & Company, BASF Wyandotte, both by John E. Knight, Attorney, Madison (January 22, 1974).

In opposition to inverted rate structure

Cross Plains Electric Company, by Harold L. Swanson, Secretary-Treasurer, Herbert Niebuhr, Superintendent, Cross Plains (October 17, 18, and 19, 1972).
American Motors Corporation, Milwaukee, by Herman J. Tiedt, Electrical Engineer, Milwaukee (October 17, 18, and 19, 1972).
Briggs & Stratton Corporation, Wauwatosa, BASF Wyandotte Corporation, Wauwatosa, both by Roger P. Paulson, Attorney, Milwaukee (October 17, 18, and 19, 1972. August 20, 21, 22, 23, and 24, 1973).
Parker Pen Company, by Philip Hull, Vice President, Janesville, (October 17, 18, and 19, 1972).
McGraw-Edison Fibre Products Division, by David J. Coughlin, Vice President, West Bend (October 17, 18, and 19, 1972).
Wisconsin State AFL-CIO, by Ken Clark, Staff Representative, Wauwatosa (October 18 and 19, 1972).,

Of the Commission staff

William E. Torkelson, Chief Counsel, Legal Division (May 24, September 11, 12, 13, and 14, October 17, 18, and 19, December 19, 20, and 21, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).
F. C. Huebner, Administrator, Accounts & Finance Division (May 24, September 11, 12, 13, and 14, October 17, 18, and 19, December 19, 20, and 21, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).
Norman C. Young, Accounts & Finance Division (September 11, 12, 13, and 14, October 17, 18, and 19, 1972).
Robert C. Mueller, Accounts & Finance Division (September 11, 12, 13 and 14, December 19 and 20, 1972).
Robert G. Dudley, Administrator, Utility Rates Division (May 24, September 11, 12, 13, and 14, October 18 and 19, December 19, 20, and 21, 1972).
Thor R. Soderholm, Utility Rates Division (May 24, September 11, 12, 13 and 14, October 17, 18, and 19, December 19, 20, and 21, 1972. August 20, 21, 22, 23, and 24, 1973. January 21 and 22, 1974).
V. W. Mayer, Utility Rates Division (August 20, 21, 22, 23, and 24, 1973. January 21, 1974).
Gary A. Evenson, Utility Rates Division (August 20, 21, 22, 23, and 24, 1973).
Alan R. Chalfant, Utility Rates Division (January 21 and 22, 1974).
Clarence F. Riederer, Engineering Division (October 17, 18, and 19, 1972).
Professor Leonard Weiss, Consultant, Madison (August 20, 21, 22, 23, and 24. 1973. January 21 and 22, 1974).

Appendix B

ELECTRIC RATES (CHANGES ONLY)

	Billing periods: Winter	Billing periods: Summer
RESIDENTIAL SERVICE—RG-1		
Rate: Fixed charge per month, $1.50, energy charge:		
1st 100 KWh per month per kilowatt-hour	$0.0250	$0.0250
Next 900 KWh per month per kilowatt-hour	.0220	.0220
Over 1,000 KWh per month per kilowatt-hour	.0150	.0220
COMMERCIAL LIGHTING AND POWER—CG-1		
Rate:		
Demand charge:		
1st 10 KW or less of demand per month	2.00	2.00
Next 490 KW of demand per month per kilowatt	2.30	2.60
Next 500 KW of demand per month per kilowatt	2.15	2.45
Over 1,000 KW of demand per month per kilowatt	1.50	2.00
Energy charge:		
1st 500 KWh per month per kilowatt-hour	2.60 cents.	
Next 9,500 KWh per month per kilowatt-hour	2.10 cents.	
Next 40,000 KWh per month per kilowatt-hour	1.45 cents.	
Over 50,000 KWh per month per kilowatt-hour	1.25 cents.	
POWER SERVICE, STANDARD RATE—CP-1		
Rate:		
Demand charge:		
1st 10 KW or less of demand per month	2.50	2.75
Next 190 KW of demand per month per kilowatt	2.10	2.25
Next 800 KW of demand per month per kilowatt	1.35	2.00
Over 1,000 KW of demand per month per kilowatt	1.25	2.00
Energy charge:		
1st 500 KWh per month per kilowatt-hour	2.55 cents.	
Next 9,500 KWh per month per kilowatt-hour	1.70 cents.	
Next 40,000 KWh per month per kilowatt-hour	1.35 cents.	
Over 50,000 KWh per month per kilowatt-hour	1.25 cents.	

Power service, optional rate—CpO-1

Rate:	
Demand charge:	
First 10 Kw or less of demand per month	$4.00
Over 10 Kw of demand per month per kilowatt	2.75
Energy charge: Per month per kilowatt-hour	.025

Municipal water pumping—Mp-1

Rate:	
Demand charge:	
1st 1,500 Kw or less per month	3,750.00
Over 1,500 Kw or less per month	2.35
Energy charge: Per month per kilowatt-hour	.0106

Oscar Mayer Co., interconnection and electric energy contract—Sp-1

Rate:	
Demand charge: Per month per kilowatt-hour of the effective contract demand	2.00
Energy charge: Per month per kilowatt-hour	.0106

University of Wisconsin, interconnection and electric energy contract—Mg-1

Rate:	
Demand charge: Per month per kilowatt of demand	2.00
Energy charge: Per month per kilowatt-hour	.009

Capitol Heating Plant, interconnection and electric energy contract—Sp-2

Rate:	
Demand charge: Per month per kilowatt of demand	2.20
Energy charge: Per month per kilowatt-hour	.009

Residential controlled water heating—Rw-1

Rate: 1.3 cent net per kilowatt-hour.

Miscellaneous flat rate service—Gf-1

Rate:

Category I

(a) Public telephone booths with not more than 75 watts of lighting load, controlled by light-sensitive cell control units (per month)	$1.60
(b) Telephone concentrators with not more than 400 watts connected for heating purposes preset at not in excess of 60° F. (per month)	.90

Category II

(a) CATV amplifiers with nominal operating wattage of 250 watts (per month)	5.80
(b) CATV amplifiers with nominal operating wattage of 325 watts (per month)	7.35
(c) CATV amplifiers with nominal operating wattage of 425 watts (per month)	10.40

Flood lighting—MIS

Rate:

First 2,000 KWh per month per kilowatt-hour net	.03
Over 2,000 KWh per month per kilowatt-hour, net	.02

Commercial temporary service—CgT

Rate:

Demand charge: 8 cents per day per kilowatt of demand.
Energy charge: 2 cents per kilowatt-hour.

Secondary service for municipal defense sirens—Mg-2

Rate: $1 per year or any part of a year for each 2 hp or fraction thereof for each siren installed.

Street lighting service—Ms-1

Rate:

Suspension type—For overhead street lighting system owned and maintained by the company:

300 W, all night schedule, per lamp per year	$42.00
150 W, all night schedule, per lamp per year	33.00
100 W, all night schedule, per lamp per year	29.00
50 W, all night schedule, per lamp per year	17.28
100 W, Midnight schedule, per lamp per year	20.00

Boulevard type—

For boulevard lighting systems owned by city of Madison, village of Maple Bluff and village of Shorewood Hills. Lamps and globes maintained by company. Boulevard posts with:

2, 500 W lamps, all night schedule, per post per year	$84.00
1, 500 W lamps, all night schedule, per post per year	42.00
1, 300 W lamps, all night schedule, per post per year	32.00
1, 200 W lamps, all night schedule, per post per year	24.00
2, 500 W lamps, midnight schedule, per post per year	66.00
1, 500 W lamps, midnight schedule, per post per year	33.00
1, 300 W lamps, midnight schedule, per post per year	24.00

For boulevard type with posts, lamps, and globes owned and maintained by customers. Boulevard posts with:

1, 100 W lamp, all night schedule, per post per year	12.00

For boulevard lighting system (limited to city of Middleton) owned and maintained by the company. Boulevard posts with:

1, 300 W lamp, all night schedule, per post per year	54.00
1, 300 W lamp, midnight schedule, per post per year	45.00

Fire alarm and obstruction marker lights

Limited to installation of fire alarm marker lights at Truax Field and obstruction marker lights in the immediate vicinity of Truax Field. Customer to furnish all fixtures, supports, and outer globes for initial installation and replacements. Lamps maintained by company.

Unit A—1–150 W overhead suspension fire alarm marker light (all-night schedule).
B—2–75 W obstruction markers per location (all-night schedule).

Rate per unit per year—$21.00

Mercury vapor street and highway lighting by company-owned street lighting facilities—Ms-2

Rate—Nominal rating:

400 W, 115/230 volt, 20,000–21,000 lumens, all-night schedule, per lamp per year	$66.00
Midnight schedule, per lamp per year	48.00
10:30 p.m. schedule, per lamp per year	41.64
250 W, 115/230 volt, 10,500 lumens, all-night schedule, per lamp per year	54.00
Midnight schedule, per lamp per year	42.00
10:30 p.m. schedule, per lamp per year	37.44
175 W, 115/230 volt, 7,900 lumens, all-night schedule, per lamp per year	44.00
100 W, 115/230 volt, 3,940 lumens, all-night schedule, per lamp per year	36.00

Mercury vapor street and highway lighting by customer-owned and maintained facilities—Ms-3

Rate—Nominal rating:

	Rate per lamp per year		
	All-night schedule	Midnight schedule	10:30 p.m. schedule
1,000 W, 55,000 lumens	$92.00	$48.00	$35.76
700 W, 37,000–41,000 lumens	65.00	34.00	25.20
400 W, 20,000–21,000 lumens	38.00	20.00	14.76
250 W, 10,500 lumens	24.00	12.40	9.36
175 W, 8,000 lumens	18.00		

Mercury vapor ornamental street lighting limited in underground residential distribution (U.R.D.) areas only—Ms-4

Rates:	*Per lamp per year*
250 W, 115/230 volt, 11,000 lumens ANEN	$34.00
175 W, 115/230 volt, 8,000 lumens ANEN	26.00

Mercury vapor ornamental street lighting limited to commercial areas only, supplied by underground distribution facilities outside the low-voltage network areas—Ms-6

Rates:	*Per lamp per year*
250 W, 115/230 volt, 11,000 lumens ANEN	$34.00
175 W, 115/230 volt, 8,000 lumens ANEN	26.00

Appendix C

SCHEDULE 1

The distribution of the revenue requirement between the various classes of service under rates in effect prior to February 13, 1973, 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 University of Wisconsin	2,468,744	2,659,205	2,672,000
Sp-2 Capitol heating plant	[1] 76,113	[1] 76,113*	80,067
Total sub to design	29,497,013	31,611,585	31,630,120
Revenue from other sales and other revenue	635,220	644,948	644,948
Total	30,132,233	32,256,533	32,275,070

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

SCHEDULE 2

RATE SCHEDULE COMPARISON

Schedule and block	Pre 2-U-7423 rates	Temporary rates	Authorized rates	
			Winter	Summer
Rg-1:				
Fixed charge	$0.75	$1.00	$1.50	$1.50
Cents per kilowatt-hour:				
1st 100 KWh	.0285	.0300	.0250	.0250
Next 400 KWh	.0203	.0225	.0220	.0220
Next 500 KWh	.0203	.0200	.0220	.0220
Next 500 KWh	.0156	.0200	.0150	.0220
Over 1500 KWh	.0156	.0164	.0150	.0220
Cg-1:				
Demand—Per kilowatt:				
1st 10 KW or less	1.00	1.50	2.00	2.00
Next 490 KW	2.20	2.35	2.30	2.60
Next 500 KW	1.95	2.20	2.15	2.45
Next 1000 KW	1.25	1.30	1.50	2.00
Over 2000 KW	.95	1.30	1.50	2.00
Energy—Cents per kilowatt-hour:				
1st 500 KWh	.0285	.0300	$0.0260	
Next 9,500 KWh	.0201	.0220	.0210	
Next 10,000 KWh	.0166	.0160	.0145	
Next 30,000 KWh	.0133	.0160	.0145	
Next 50,000 KWh	.0112	.0120	.0125	
Over 100,000 KWh	.0105	.0120	.0125	
Cp-1:				
Demand—Per kilowatt:				
1st 10 KW or less	2.00	2.50	2.50	2.75
Next 190 KW	1.85	2.10	2.10	2.25
Next 800 KW	1.10	1.35	1.35	2.00
Over 1,000 KW	.95	1.25	1.25	2.00
Energy—Cents per kilowatt-hour:				
1st 500 KWh	.0285	.0300	$0.0255	
Next 9,500 KWh	.0130	.0140	.0170	
Next 40,000 KWh	.0112	.0130	.0135	
Next 50.000 KWh	.0112	.0120	.0125	
Over 100,000 KWh	.0105	.0120	.0125	

Schedule and block	Pre 2-U-7423 rates	Temporary rates	Authorized rates
CpO-1:			
Demand:			
1st 10 KW or less	$2.25	$2.50	$4.00
Over 10 KW (per kilowatt)	1.25	1.50	2.75
Energy: Per kilowatt-hour (cents per kilowatt-hour)	.0350	.0350	.0350
Mp-1:			
Demand charge:			
1st 1,500 KW or less	2,220	2,625	3,750
Over 1,500 KW (per kilowatt)	1.44	1.50	2.35
Energy charge (cents per kilowatt-hour):			
1st 150 hours use of demand	1.33	1.50	
Over 150 hours use of demand	1.00	1.10	
Per killowatt-hour			1.06
SP-1 Oscar Mayer:			
Demand charge:			
1st 10 percent of contract demand (per kilowatt)	1.67		
Remaining 90 percent of contract demand (per kilowatt)	.85		
Per killowatt of contract demand		1.255	2.00
Energy charge:			
1st 55 hours (cents per kilowatt-hour)	2.20	2.20	
Over 55 hours (cents per killowatt-hour)	1.00	1.10	
Per killowatt-hour (cents)			1.06
MG-1 University of Wisconsin:			
Demand (per kilowatt)	.925	1.25	2.00
Energy per killowatt-hour (cents per kilowatt-hour)	.0097	.0105	.0090
SP-2 Capitol heat plant:			
Demand per killowatt		1.25	2.20
Energy per killowatt (cents)		.0111	.0090

Representative MOORHEAD. We thank you very much for an excellent presentation to this committee. We would now like to hear from Professor Weidenbaum, who is no stranger to the members of this committee. We welcome you back here, sir.

STATEMENT OF MURRAY L. WEIDENBAUM, PROFESSOR OF ECONOMICS, WASHINGTON UNIVERSITY, ST. LOUIS MO.

Mr. WEIDENBAUM. Thank you, Mr. Chairman. It is always a pleasure to testify before the Joint Economic Committee. I have given the staff my larger report on electric utilities,[1] and I will summarize very briefly the findings of that report together with my full statement.

The very serious problems facing the electric utility industry require a combination of sensible public and private actions plus restraint in avoiding solutions that would only worsen the situation.

The cost of producing electricity has risen sharply, mainly due to two factors beyond the control of the companies—rising costs of fuel —the basic raw material of electric utilities—and rising interest on bonds issued to pay for the expensive facilities needed to produce electricity.

An ordinary industry would raise its prices to cover these rising costs. But the price of electricity is closely controlled by government regulatory agencies. The regulatory commissions have been allowing substantial rate increases, but they have not kept up with cost increases. The backlog of undecided rate cases rose from $1.1 billion on June 30, 1972, to $2.7 billion on June 30, 1974. The result has been declining earnings for utilities; numerous traditional dividend increases have not been forthcoming.

Well, why worry about electric utility stockholders? There is a very hard-nosed reason. Because this industry has a low rate of profits and an even lower rate of retained earnings, it can finance only a small part of its new facilities with its own money. Most of the funds to pay for new capacity—about two-thirds—must come from investors who purchase utility stocks and bonds.

The typical utility is limited in the amount of funds that it can issue. "Indenture" agreements accompany existing bonds usually require that operating income be twice—or more—than the interest payments. With the rapid rise in operating expense and interest rates, many companies are very close to the minimum interest "coverage" ratio required to meet the legal obligations to existing bondholders. This situation will worsen as old bonds with low interest rates mature and have to be replaced by bonds with current higher interest rates.

Thus, many utilities are or soon will be in a situation where they cannot sell more bonds. Some utilities have been selling new stock, but many companies in the industry find little public interest in purchasing their shares because of what is happening to existing shareholders.

Again, why should the average citizen and taxpayer worry? Because if the utilities are unable to finance needed expansion, they have to cut back on the new capacity to meet the electricity needs of a rising population. Many have been forced to do just that—and reserve margins later in the decade will be declining. The industry will need $140 billion for the period of 1974–80. It is going to be extremely difficult for the electric utilities to raise that amount of capital, particularly in view of the competition for funds from other industries which are not subject to rate regulation.

I would like now to turn to the role of public policy. On the basis of sad experience, we should learn what to avoid.

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[1] See "Financing the Electric Utility Industry," beginning on p. 184.

First of all, we should not set up new long-term programs on the basis of a short-term problem. The utility financing problem is very serious right now and programs to be effective in 1980 won't help. Second, we should not establish national policy on the basis of the most extreme case. Consolidated Edison is not typical of the industry. Many of its problems are industrywide, but not nearly so severe.

Nor should a tax credit be given to deal with the financing problem. Every industry should pay its full share of taxes. If an industry is not enjoying financial health, we must look to more basic causes. And government resources should not now subsidize the use of electricity. When national policy is encouraging the conservation of energy, it would be stupid to use the power of government to keep the price of electricity below the true costs of producing it.

The Government should not set up another credit program. Having the Government guarantee private bonds is not as free as it looks. Such programs do nothing to increase the supply of investment funds. They merely elbow out the unprotected borrowers, which is why each new credit program only leads to demands from still other groups for still more credit programs. The proliferation of these programs also raises interest rates, including the interest on Treasury debt—a cost borne by the taxpayer. In the case of utilities, credit guarantees would be unworkable because of the bond "indentures" I mentioned and other legal restrictions.

I believe there is no justification for the Government taking over an industry simply because it is facing financial problems. Government ownership will not reduce the real costs of electricity. A ton of coal or a barrel of oil costs just as much whether the shares of the utility are held by the Treasury or by a pension fund. In fact, Government ownership would only paper over the problem by hiding the true costs. As we see in the ConEd case, when Government takes over a powerplant it does not pay local property taxes, but shifts the burden to other taxpayers.

Finally, Congress should avoid taking actions, albeit designed to help an industry, which increase inflationary pressures and especially interest rates, which hit this industry particularly hard. Government expenditures subsidies and credit guarantees are examples of such shortsighted policies.

What should be done? There is no escaping the need for prompt action by regulatory commissions on requested increases in electric utility rates. The longer they wait, the larger will be the rate increases required to restore confidence in the industry's finances. It may be a paradox, but the way to maintain lower utility rates in the long run is to grant adequate rate increases in the short run, because the utility that impresses potential investors as providing a relatively assured return on their investment can raise new capital at lower rates, hence lower costs to the users, then companies considered to be higher risks.

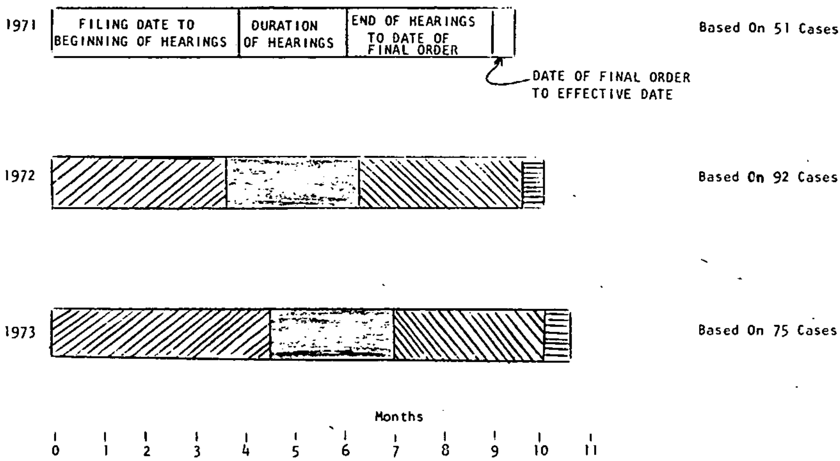
The procedures of many State regulatory commissions need to be modernized. Regulatory lag should be reduced, when it is increasing. [See figure 1.] One out of very four cases takes longer than 1 year.

[The figure referred to appears on p. 183.]

Mr. WEIDENBAUM. There is too large a gap between the most advanced and the least advanced standards. Rather than a matter of luck, every utility should be allowed to use automatic fuel pass-through clauses, future test years, normalization of tax incentives, charges for late payments, and interim increases.

Figure 1

REGULATORY LAG ANALYSIS OF ELECTRIC UTILITY
Rate Cases Decided By State Utility Commissions, 1971-73



But prompt action on rate increases is not the only change that is required. Demand for electrical power is uneven, and this increases costs. The key thing is that the least efficient generating units are used during the peak periods, particularly the summer.

If the electrical load could be made more level, the most efficient units could be operated to capacity most of the time and the inefficient ones would be used much less. This will require revising rate structures to dampen down-peak loads. Yes, I am sure the installation cost of metering equipment when bought in small amounts is very high, but as American industry has shown, mass production brings down the unit cost. Utilities should charge lower rates during offpeak periods, and higher rates during the times of peak usage. The basic principle to be followed should be that charges for providing service not encourage greater usage. Other utilities, other regulated industries, do this. Just look at the telephone companies. Look at the airlines. It is not a very radical and theoretical proposal. It is in practice, and it works.

A fundamental redirection in utilities thinking is required. After all, the present generation of management grew up in a period of technological advancement which led to declining costs. That is not here any more, but during that earlier period, literally the more electricity was used, the lower the average rate. Now rising usage of air-conditioning and other peak uses only brings costs higher by requiring increasingly expensive generating equipment. The individual utility has no continuing need now to constantly seek ever-larger usage. Those utilities which have not done so, should shift their advertising to encourage offpeak uses and to educate consumers on how to conserve power. When I say that, I don't just mean the top management. I mean the rank and file. Listen to their statements. There is quite a gap there.

Voluntary conservation efforts may be desirable, but we cannot rely on them too heavily. Electricity use did decline in the fall of 1973 with the oil embargo. However, before this spring, before the embargo was lifted, usage began exceeding year-ago levels. Voluntary measures are difficult to sustain beyond periods of immediate crisis. We should avoid subsidizing energy use and encourage pricing at full cost in order to discourage high usage [the existing large and generous array of income maintenance policies should deal with the special problems of the poor].

Discriminatory tax treatment of utilities should be eliminated. We must realize governments at every level tax utilities more heavily than other business. At the local level, this is merely a subterfuge for substituting utility-rate increases for property-tax increases. In the present environment of rapidly rising utility rates, that is indefensible.

At the Federal level, the Congress should promptly increase the 4-percent investment credit to the level available to all other industries. I wouldn't give them a nickel more, but I couldn't give them a nickel less. All State regulatory commissions should allow utilities to receive the benefit of that change, but only half do so now, and some only in part.

The basic way to provide more capital for the needs of the Nation is not to subsidize one industry or another, but to increase the size of the pool of investment funds for which all borrowers can compete. Future changes in the tax system should give greater weight to saving. The Federal Government should reduce the massive extent to which it now competes with the private sector for the limited supply of investment funds. The problems facing investor-owned electric utilities are severe, but not unique. The basic solution is to provide adequate capital funds to meet the growing needs of the American society.

To conclude, through inadequate action or delays in action by the State regulatory commissions, the electric utility industry may be forced to come hat-in-hand to the Congress for a bailout. That could be in the near future if the State commissions do not meet their responsibilities.

The current difficulties being experienced by utilities reflect the lack of confidence by investors in the willingness of the State regulatory commissions to meet their obligations.

Despite the political unpopularity of rate increases, we must acknowledge that the current level of utility rates is not in the long interest of the consumer. Today's rates are not adequate to generate the capital required to build the capacity to serve the public in the future. There is no excuse for the State commissions passing the buck to the Federal Government.

Thank you, Mr. Chairman.

[The report referred to in Mr. Weidenbaum's statement follows:]

Financing the Electric Utility Industry—Highlights [1]

Chapter 1. Findings and Conclusions

These are the policy highlights of this study of financing investor-owned electric utilities.

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[1] A report prepared by Murray L. Weidenbaum for Edison Electric Institute, September 1974. Murray L. Weidenbaum *is Mallinckrodt Distinguished University Professor at Washington University, St. Louis, Mo.*

THE FINANCIAL CONDITION OF ELECTRIC UTILITIES

1. The pressures facing investor-owned electric utilities attempting to finance needed capital expansion programs in the current economic environment are real and serious. The industry's capital needs are likely to total $140 billion in the 1974–80 time period.

2. The importance of the industry and the seriousness of the situation require key changes in public and private policies.

CHANGES IN REGULATORY POLICIES

3. There is no escaping the need for substantial increases in electric utility rates. These can be justified on grounds of financial need as well as economic efficiency. None of the other proposals—individually or collectively—obviate the need for this unpleasant but necessary course of action.

4. The decision-making procedures of many state regulatory commissions need to be modernized. There is too large a gap between the most advanced and the least advanced standards and policies.

5. Rather than a matter of luck or happenstance, every utility should be allowed to use automatic fuel pass-through clauses, future test years, normalization of tax incentives, charges for late payments, and interim increases.

6. Regulatory lag should be reduced. Only 28 percent of the cases settled during 1971–73 were completed in six months or less. One out of every four cases took longer than one year. These delays contribute to the "revolving door" phenomenon whereby no sooner is a utility granted one rate increase than it applies for another.

7. Utility rate structures should be revised in order more effectively to dampen down peak-load demand and encourage usage during off-peak periods. These changes should be consistent with the basic principle that charges to given classes of customers should reflect the costs of providing service.

CHANGES IN MANAGEMENT PRACTICES

8. Utility managements are changing and should change their basic outlook from the historically relevant notion of market expansion to the current need for economy and efficiency in the use of electric power. This shift in priorities in good measure is now feasible because of the earlier successes of the industry in developing the uses of electricity.

9. Those electric utilities which have not already shifted their advertising away from peak-demand uses should do so. An even greater emphasis should be put on educating customers in how to use electricity more efficiently. Reduction of peak usage will directly ease the industry's capital requirements and financing needs.

CHANGES IN GOVERNMENT TAX TREATMENT

10. The Congress should promptly raise the 4 percent investment tax credit for utilities to the 7 percent available to all other industries. This differential treatment is not justified under present circumstances.

11. State and local governments should refrain from instituting or increasing special taxes on electric utilities. These companies should pay the same tax rates as firms in other industries. It would be helpful—although given the political realities not very likely—if the existing special taxes on utilities were to be repealed.

CHANGES IN GENERAL ECONOMIC POLICY

12. Changes in government legislation and policy should give greater weight to fostering an economic climate that is more conducive to private saving and investment. The basic way to provide more capital for the needs of the nation is not to subsidize a given industry but to increase the size of the pool of investment funds for which all borrowers can compete.

13. The Federal government itself should reduce the massive extent to which it now competes with the private sector for the limited supply of investment funds. During this inflationary period, the budget deficit and Federal credit subsidies should be reduced if not eliminated. Proposals for Federal guarantees of utility bonds are misguided in principle and unworkable in practice.

14. Future changes in the tax system should give greater weight to saving than to consumption. It is private saving that is the basic source of financing of the capacity to provide for future consumption.

15. Government restrictions and regulations which give an inflationary bias to the economy—be they subsidies to labor, agriculture, or business—should be

sharply curtailed, especially those that reflect the needs of the 1930's rather than the 1970's.

CHAPTER 2. THE PRESENT FINANCIAL CONDITION OF THE ELECTRIC UTILITY INDUSTRY

THE COST STRUCTURE OF THE INDUSTRY

The predominant characteristic of the electric utility industry's cost structure is its capital intensiveness. Gross plant investment of about $4.50 is required on average to produce $1.00 of annual revenue. After adjustments for depreciation, net assets equal nearly $4.00 to generate $1.00 revenue. This compares with much lower ratios of assets to sales in other industries.

Being capital intensive, the cost of capital plays an important part in determining the ultimate price the electricity industry must charge for its product. Likewise, the other fixed charges associated with investment—depreciation, insurance and property taxes—weigh heavily in the total cost of delivered energy. To keep its total cost per unit of output as low as possible, a utility must seek to spread these fixed costs over the largest output possible. Thus, load factor is important in utility economics. Load factor is the ratio of actual output to the potential output associated with around-the-clock use of maximum annual supply. To the extent that the load factor is increased, the portion of total costs per kilowatt-hour represented by fixed costs will decline.

Fixed costs

Normally, more than 50 percent of the total cost of electric service can be termed "fixed" or not directly related to output. This percentage can vary from year to year primarily as a function of fuel cost, which is by far the largest component of variable cost. Table 1 outlines the evolution of fixed and variable costs as percentages of total revenue over the past 10 years.

TABLE 1.—FIXED AND VARIABLE ELEMENTS OF COSTS OF PRODUCING ELECTRICITY

	Cost category									
	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
Variable costs:										
Fuel	15.4	15.4	16.0	16.1	16.8	17.3	19.8	21.9	22.5	24.4
Maintenance	6.8	6.8	6.7	6.9	6.7	6.9	7.3	7.1	7.3	7.2
Other operating expenses	19.6	19.6	19.4	19.2	19.0	19.2	19.1	18.8	18.6	17.5
Subtotal, variable costs	41.8	41.8	42.1	42.2	42.5	43.4	46.2	47.8	48.4	49.1
Fixed costs:										
Depreciation	11.8	11.8	11.5	11.9	11.7	11.7	11.7	11.4	11.0	10.9
Taxes	23.0	22.3	22.1	21.6	22.0	20.9	18.3	17.4	17.2	16.5
Operating income after taxes	23.4	24.1	24.3	24.3	23.8	24.0	23.8	23.4	23.4	23.5
Subtotal, fixed costs	58.2	58.2	57.9	57.8	57.5	57.0	53.8	52.2	51.6	50.9

Trends in plant costs

Over most of the history of the electric utility industry, plant costs per kilowatt of capacity remained stable or showed a downward trend. Economies of scale available in production, transmission, and distribution were normally sufficient to offset the effects of inflation. Today economies of scale still exist, though perhaps to a lesser degree than in the past. Since the late 1960's, however, the gains from advancing technology and increasing plant size have been more than offset by the costs arising from inflation. The current dollar cost of additional capacity is above the embedded or historical costs of facilities already in service.

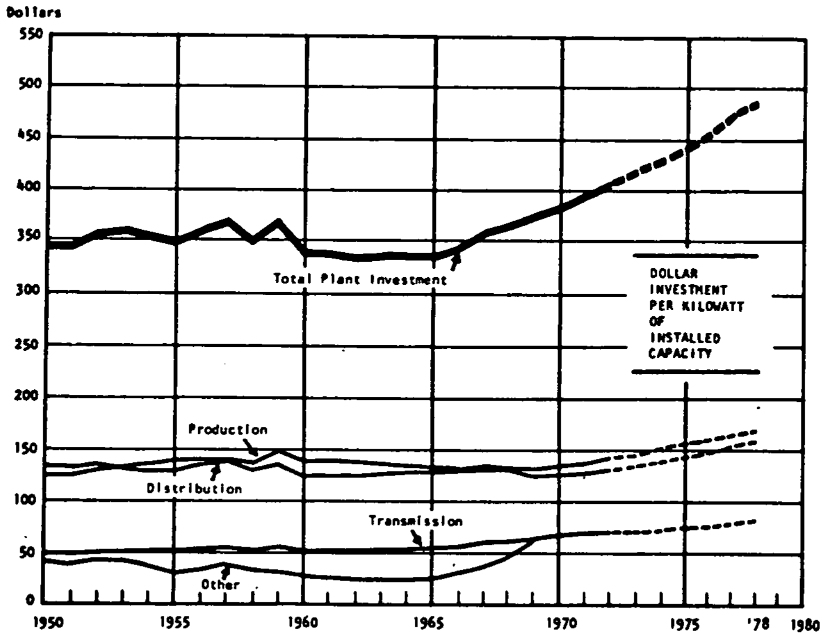
PROFITABILITY OF THE INDUSTRY

Allowable rates of return

In granting or authorizing an increase in rates, regulatory commissions frequently do not specify the level of permissible return on common equity but instead announce a permitted rate of return; that is, the total of profit plus interest as a percent of capital (the latter is usually referred to as the "rate base"). Depending on the capital structure of the utility and the costs of debt and preferred stock, a given overall rate of return may imply varying rates of allowable profits on common stock equity.

Figure 1

TREND IN COST OF FACILITIES



Some idea of the differing views held by various state regulatory agencies as to the necessary return on equity can be gleaned by comparing data on returns requested with returns granted over the past few years. In 1973 out of some 45 final rate decisions surveyed, 39 had involved requests for after-tax returns on equity of 12 percent or more. However, only 29 of the final orders permitted returns at or above the 12 percent level. The average rate of return (unweighted) granted in the 45 decisions surveyed in 1973 was 11.9 percent, compared to the average requested of 13.15%.

Data collected by the Federal Power Commission show that the range of actual return on common equity extends from below 5 percent to over 18 percent. However, of the companies covered by this survey, the percentage earning 12 percent or more on common has declined since 1969. In that year 45 percent of the companies had a rate of return on equity of 12 percent or more. In 1970 the figure was 40 percent, in 1971 39 percent, and in 1972 40 percent.

TABLE 2.—RATES OF RETURN REQUESTED AND ALLOWED, ELECTRIC RATE CASES SETTLED, 1971–73

Period of decision	Number of decisions	Average unweighted return sought (percent)	Average unweighted return granted (percent)
1971	40	12.62	11.90
1972	57	13.11	12.24
1973	45	13.15	11.92

Inflation and utilities

Although inflation is a serious problem for most sectors of the economy, it is especially significant for the electric utilities because of their tremendous need for new capital. A typical utility requires about $4 of capital to generate one dollar of revenue. In contrast, the average manufacturing company needs only 75 cents to produce a dollar of revenue. Inflation not only increases the cost of capital, but magnifies the amount needed.

Most manufacturing operations have equipment with a much shorter life. The more rapid turnover of plant and equipment investment enables the manufacturing company to react more quickly in pricing its products. They are also able to adjust prices, control expenditures, vary product and inventory lines, and effect other internal policies with greater freedom.

The after-tax return on investment in electric utilities typically is below the average for other leading industries. The average return on net worth for leading electric and gas utilities of 10.8 percent in 1973 was significantly below the returns of large non-financial corporations (13.2 percent) and of large manufacturing companies (14.8 percent). Given the new higher level of risk in electric utility operations, such differentials no longer seem to be appropriate.

Trends in utility stock indices

The particular financial problems of electric utilities have compounded the effects of a stagnant stock market on utility shares. Declining interest coverage ratios have required an increased reliance on common stock sales with their diluting effect on earnings per share. All of this has occurred at a time when placement of additional shares must be made at prices below book values because of the depressed state of the equity markets.

Data on the comparative performance of the Moody's 125 Industrials and 24 Utilities averages reveal the acute difficulty being experienced by utility companies (see Table 3). Since 1970, the utility index has failed to track the industrial average during market rises. The year 1972 was especially significant in this regard. While the 1972 average price level of the industrials was 14 percent higher than 1971, the utility index was 5 percent below 1971. Both indices declined over 1973. The utility average fell by 11 percent, compared to only 2 percent for the industrials.

Poorer performance on the part of the utility index was undoubtedly due to the stagnation in per share earnings growth. Between December 1972 and June 1974, average earnings per share of the industrial group rose by nearly 30 percent while that of the utility group declined by 6.5 percent.

THE PHYSICAL CAPITAL INTENSITY OF THE INDUSTRY

The electric utility industry has the highest ratio of investment to revenue of any sector of the industrial economy. For investor-owned electric utilities this ratio has consistently averaged near 4, as data for the 10-year period 1964–1973 illustrate (see Table 4).

Other industries normally have much lower ratios of net assets to revenues. After electric utilities the next most capital-intensive industry is communications where revenue equals assets once in just under 3 years. Railroads normally require more than 2½ years for revenues to match assets, and gas utilities and pipeline companies require about 2 years. The great bulk of manufacturing industries, however, turn over their assets in less than one year.

TABLE 3.—MOVEMENTS IN UTILITY AND INDUSTRIAL STOCK PRICES

	Price/earnings ratio	Earnings per share
MOODY'S 24 UTILITIES AVERAGE		
Year and date:		
1974:		
June	6.0	7.23
March	8.6	7.15
1973:		
December	8.1	7.55
September	9.5	7.60
June	9.2	7.63
March	9.7	7.78
1972: December	10.8	7.73
MOODY'S 125 INDUSTRIALS AVERAGE		
1974:		
June	10.6	31.60
March	11.8	24.70
1973:		
December	12.4	29.18
September	14.4	23.77
June	15.1	27.15
March	17.3	23.95
1972: December	19.2	24.42

TABLE 4.—CAPITAL INTENSITY OF THE ELECTRIC UTILITY INDUSTRY

Year	Average assets for the year (in millions)	Electric revenues (in millions)	Assets/revenue
1964	$46,963	$12,211	3.85
1965	49,243	12,887	3.82
1966	52,260	13,773	3.79
1967	56,299	14,569	3.86
1968	61,346	15,810	3.88
1969	67,365	17,164	3.92
1970	75,090	18,830	3.99
1971	84,742	21,230	3.99
1972	95,861	24,133	3.97
1973	108,234	27,526	3.93

THE FINANCIAL CAPITAL STRUCTURE OF THE INDUSTRY

Debt/equity ratios

The investor-owned electric utility industry is characterized by a highly leveraged capital structure, a far higher proportion of debt to stockholders' investment than is present in most other industries. Reliance on long-term debt plus preferred stock has been justified historically by the past pattern of stability of net income growth. This is a characteristic which, at least in the past, has been associated with regulated utilities as a general proposition; shareholders of a company are wary of large amounts of debt because the payment of interest on this indebtedness takes precedence over the payment of dividends.

This stability in earnings growth hence was quite important. It allowed the common equity investor to view high debt ratios with little concern because of his confidence in the availability of adequate earnings. Other industries, which lack stable growth in their net income, have depended less on debt financing and normally seek to generate a large portion of their new capital internally. When outside financing is needed, firms in these industries more often resort to the sale of new equity.

Over the past few years, electric utilities have seen their interest burdens increase rapidly because of two factors: 1. long-term interest rates have risen dramatically and 2. steadily expanding construction programs required more capital. Since 1964, yields on utility bonds have nearly doubled while annual construction expenditures have more than quadrupled (see Table 5).

TABLE 5.—ELECTRIC UTILITY CAPITAL OUTLAYS AND BOND YIELDS

Year	Overall average yields of utility bonds end of year average (percent)	Electric construction expenditures (millions)
1964	4.53	$3,567
1965	4.85	4,050
1966	5.63	4,962
1967	6.56	6,140
1968	6.85	7,168
1969	8.57	8,323
1970	8.29	10,182
1971	7.87	11,939
1972	7.48	13,435
1973	8.21	14,979

Together these two developments have meant that maintenance of previous debt/equity ratios could only result in a substantial climb in the annual level of interest charges on long-term debt. Reacting to these pressures, electric utilities have attempted to alter the mix of their incremental long-term financing by expanding their sales of preferred and common stocks. This has led to some reduction in the share of long-term debt in the industry's capital structure, from 55.3 percent in 1970 to 52.9 percent in 1973.

Trends in the mix of new long-term financing illustrate the relative shift away from debt as a means to fund new construction since 1968 (see Table 6).

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TABLE 6.—COMPOSITION OF NEW LONG TERM CAPITAL (PERCENTAGE DISTRIBUTION)

Year	Long term debt	Preferred stock	Common stock	Retained earnings	Total
1968	64.3	9.3	9.2	17.2	100.0
1969	65.3	7.2	11.5	16.0	100.0
1970	57.6	12.7	19.3	10.4	100.0
1971	50.0	17.1	24.5	10.8	100.0
1972	35.3	20.1	23.0	11.6	100.0
1973	45.9	15.1	26.6	12.4	100.0

Most electric utility mortgage indentures require the company to maintain a specified minimum ratio of earnings to interest charges (either on a before- or after-tax basis). As this ratio declines toward the specified minimum, additional debt financing becomes increasingly difficult. In addition, the utility's bond rating is likely to be reduced which means an increase in the interest cost of new debt and further aggravation of the coverage problem. For the electric utility industry as a whole, the coverage of interest charges has declined steadily since 1965 (see Table 7).

TABLE 7.—INCOME AND INTEREST OF ELECTRIC UTILITIES

Year	Income before interest charges (millions)	Interest on long-term debt (millions)	Ratio
1965	$3,454	$953	3.62
1966	3,692	1,040	3.55
1967	3,948	1,180	3.35
1968	4,179	1,373	3.04
1969	4,548	1,621	2.81
1970	5,009	2,010	2.49
1971	5,545	2,447	2.27
1972	6,302	2,849	2.21
1973	7,134	3,271	2.18

An indication of further upward pressures on interest charges can be obtained from examining the calendar of refinancing of the industry's existing debt. About $8.2 billion of public utility bonds and notes will mature during the period 1974–78, approximately $1.2 billion of this amount in 1974 and $2.4 billion in 1975. Over half of the public utility debt to be refunded during 1974 and 1975 carries coupons of less than 4 percent (see Table 8). The implications of refunding this debt at prevailing rates, even assuming some ease in money and credit markets, are very substantial.

TABLE 8.—MATURING PUBLIC UTILITY BONDS AND NOTES

[In millions of dollars]

	Interest coupon on maturing issues (Percent)											
	1.00–1.99	2.00–2.99	3.00–3.99	4.00–4.99	5.00–5.99	6.00–6.99	7.01–7.99	8.01–8.99	9.00–9.99	10.00–10.99	No coupon	Total
1974		129	545	24	6		75	284	53	50		1,166
1975		823	520	20	13		1	738	314		1	2,430
1976		573	182	61	10	35	225	332	68			1,485
1977		402	545	93	116	298	166	25	10			1,654
1978		60	794	93	82	247	150					1,425
1974–78		1,987	2,586	291	227	580	617	1,379	445	50	1	8,160

Trend in bond ratings

The concurrent rise in capital requirements and interest rates has produced a rate of increase in debt service charges exceeding the growth of electric utility earnings. This in turn has led to a steady decline in the ratio of earnings to interest, a decline so pronounced that for many companies this key index has fallen to the minimum level permitted by indenture restrictions and effectively arrested the issuance of additional debt. An inevitable result of the deteriorating earnings coverage has been a series of utility bond deratings by the major rating organizations. Each derating signals a higher cost of debt for the utility concerned and further restricts the potential market for future bonds.

During the period 1970–1973, deratings occurred with great frequency. In total, 13 electric utilities had their credit ratings lowered at least once by Moody's Investors Services, one of the two principal firms involved in credit evaluation. Over the same period the industry's combined earnings/interest coverage ratio declined from 2.5 to 2.2., measured on a basis which excludes AFDC from income totals. With the onset of the serious problems in utility earnings which accompanied the "energy crisis" of the winter of 1973–1974, the number of deratings has increased sharply. Between January and June 1974, the bonds of the following 14 electric utilities were downgraded by Moody's Investor Services:

	From	To	Category
February 1974:			
Consolidated Edison of New York	AA	Baa	Mortgage bonds.
Public Service of New Hampshire	A	Baa	Do.
Baltimore Gas & Electric	AAA	AA	Do.
	AA	A	Debentures.
April 1974:			
Western Massachusetts Electric	AA	A	Mortgage bonds.
Detroit Edison	AA	A	Do.
Columbus & Southern Ohio	AA	A	Do.
	A	Baa	Debentures
May 1974:			
Iowa Electric Light & Power	AA	A	Mortgage bonds.
Savannah Electric & Power	A	Baa	Do.
	Baa	Ba	Debentures.
Consumers Power	A	Baa	Mortgage bonds.
	Baa	Ba	Debentures.
Eastern Utilities Associates & Subsidiaries	Baa	Ba	Mortgage bonds.
Florida Power	A	Baa	Do.
	AA	A	Preferred stocks.
Florida Power	A	Baa	Do .
	AA	A	Preferred stocks.
June 1974:			
Delmarva Power & Light	AA	A	Mortgage bonds.
Boston Edison	A	Baa	Do.
Virginia Electric and Power	AA	A	Do.
	A	Baa	Debentures.

The effect of deratings is, as noted, to raise the cost of debt and constrain its marketability. The higher cost effect is apparent from the figures in Table 9 which relate percent cost to rating level for 65 investor-owned companies surveyed by the EEI Investor Relations Committee. As bond ratings move downward from the highest (AAA) grade, the percentage of companies surveyed paying more than 8% for debt in 1973 increased.

TABLE 9.—DISTRIBUTION OF 65 PRIVATELY OWNED ELECTRIC UTILITIES BY BOND RATINGS VERSUS COST OF DEBT INCLUDED IN COST OF CAPITAL USED FOR ECONOMIC EVALUATIONS

Cost of debt	Bond rating AAA	AA	A	Less than A	Distribution by cost of debt
Up to and including 7.00	1	9	2	2	14
7.01 to 7.50	1	3	1	1	6
7.51 to 8.00	2	9	5	1	17
8.01 to 8.50	1	5	11	2	19
8.51 to 9.00		3	3		6
9.01 to 9.50		1	1	1	3
Distribution by bond rating	5	30	23	7	65

For the years 1966–1973, industry-wide averages prepared from Moody's data for utility stocks and bonds likewise reveal the cost effect of credit or quality deratings. These averages are set out in Table 10.

Legal and other restrictions on leverage

In all utility long-term debt indentures there is a limitation on the issuance of debt securities, usually referred to as the "coverage requirement." The general effect of this limitation is that the company may not issue new bonds or debentures if the ratio of earnings to interest charges has been less than 2.0 for twelve of the fifteen months prior to the month in which the new securities are to be issued.

TABLE 10.—MOODY'S AVERAGE YIELDS ON UTILITY BONDS AND STOCKS— BY MOODY'S BOND RATINGS AND STOCK QUALITY GROUPS

[In percent]

End of month	Bonds					Preferred stocks			Common Stocks					
	Overall [1] average	Rating							High quality		Good quality		Medium quality	
		Aaa	Aa	A	Baa	High quality	Good quality	Medium quality	Yield	E/P ratio [2]	Yield	E/P ratio [2]	Yield	E/P ratio [2]
1973:														
December	8.21	7.90	8.10	8.24	8.59	8.04	8.35	8.24	8.06	11.27	8.24	11.19	7.75	10.91
September	8.07	7.76	7.92	8.08	8.52	7.72	8.04	8.08	6.84	9.52	6.92	10.32	7.08	9.97
June	7.73	7.53	7.63	7.78	7.97	7.53	7.62	7.75	6.88	9.65	6.93	10.19	7.26	10.38
March	7.67	7.44	7.52	7.69	8.01	7.39	7.53	7.60	6.42	9.34	6.69	9.83	6.72	9.80
1972:														
December	7.48	7.29	7.39	7.51	7.74	7.32	7.56	7.77	5.52	8.07	6.07	8.91	6.27	9.05
September	7.63	7.42	7.50	7.64	7.96	7.37	7.61	7.82	6.12	9.18	6.47	9.72	6.94	9.58
June	7.77	7.41	7.57	7.80	8.30	7.28	7.43	7.71	6.37	9.31	6.73	9.93	6.72	9.40
March	7.81	7.53	7.69	7.76	8.25	6.99	7.26	7.58	5.96	8.55	6.23	8.88	6.42	8.87
1971:														
December	7.87	7.50	7.76	7.80	8.40	7.15	7.39	7.87	5.65	7.84	5.81	8.25	6.06	8.31
September	8.10	7.76	7.95	8.23	8.45	7.28	7.55	8.06	6.23	8.56	6.18	8.99	6.46	8.98
June	8.35	7.98	8.20	8.45	8.77	7.31	7.58	8.13	5.95	8.00	5.65	7.91	6.17	8.32
March	8.03	7.56	7.98	7.99	8.59	6.91	7.11	7.74	5.55	7.51	5.36	7.71	5.80	7.83

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1970:														
December	8.29	7.80	8.20	8.23	8.91	7.30	7.55	8.43	5.77	7.69	5.23	7.52	6.75	7.95
September	8.75	8.33	8.63	8.79	9.24	7.76	8.00	8.56	6.38	8.76	6.15	8.99	7.67	8.92
June	9.20	8.89	9.00	9.22	9.67	7.84	8.13	8.56	6.88	9.51	6.85	10.24	7.36	9.96
March	8.37	8.10	8.18	8.26	8.94	7.26	7.47	8.43	5.62	7.71	5.29	7.99	6.14	8.08
1969:														
December	8.57	8.05	8.40	8.76	9.05	7.54	7.80	8.53	5.63	7.98	5.42	8.27	6.04	8.34
September	7.79	7.40	7.67	7.82	8.27	7.09	7.08	7.71	5.48	7.79	5.31	8.01	6.36	8.69
June	7.47	7.13	7.38	7.45	7.90	6.71	6.87	7.32	5.15	7.16	4.75	7.16	4.88	6.57
March	7.37	7.09	7.23	7.40	7.74	6.39	6.58	7.13	4.75	6.54	4.47	6.75	5.18	7.20
1968:														
December	6.85	6.52	6.75	6.87	7.23	6.32	6.52	6.97	4.45	6.20	4.35	6.54	4.91	8.46
September	6.27	6.03	6.12	6.27	6.67	5.97	6.17	6.64	4.77	6.73	4.57	6.88	4.96	6.72
June	6.60	6.32	6.46	6.62	7.01	6.17	6.33	6.84	4.55	6.36	4.49	6.89	4.85	6.78
March	6.39	6.13	6.26	6.41	6.75	6.04	6.28	6.63	4.85	7.01	4.69	7.41	5.28	7.52
1967:														
December	6.56	6.33	6.41	6.63	6.88	6.25	6.46	6.98	4.59	6.58	4.67	7.05	5.13	7.30
September	6.04	5.84	5.91	6.06	6.33	5.70	5.86	6.23	4.43	6.29	4.41	6.85	4.85	6.93
June	5.90	5.69	5.75	5.91	6.23	5.49	5.76	5.96	4.47	6.21	4.29	6.62	4.80	6.83
March	5.37	5.16	5.20	5.38	5.74	5.15	5.47	5.71	3.89	5.83	3.90	6.23	4.60	6.59
1966:														
December	5.63	5.34	5.43	5.67	6.07	5.46	5.72	5.94	3.89	5.78	3.69	6.03	4.51	6.47
September	5.78	5.52	5.69	5.83	6.07	5.56	5.72	5.86	4.32	6.36	4.49	6.90	4.79	6.87
June	5.33	5.18	5.21	5.42	5.52	5.12	5.35	5.56	4.06	5.88	4.14	6.29	4.47	6.26
March	5.23	5.08	5.15	5.29	5.38	4.96	5.21	5.29	3.79	5.44	3.92	5.92	4.31	5.98

[1] Average yield for 40 utility bonds, 10 in each of the 4-top quality ratings shown.
[2] Ratio in percent is obtained by dividing earnings per share by market price per share.

Note. Yields shown under preferred stocks and common stocks represent averages of 10 companies in each quality group.

In a few indentures, the ratio is as low as 1.75 and in some cases over 3.0. In the majority of cases, the required coverage ratio is 2.0. The effect of this limitation is that new long-term debt cannot be sold if the company's earnings, before the payment of Federal income tax, is not at least double the amount of interest it is required to pay on its long-term debt securities outstanding and proposed to be issued.

In 223 electric utility rate cases settled during the three-year period 1971–1973, 212 or 95 percent of the utilities had indentures which specified that interest payments must be covered at least 200 percent by earnings before interest and income taxes (see Table 11). In the 202 cases where data were available, a greater proportion of the earlier cases reported high coverage ratios than did the more recent cases. In the period January 1, 1971–March 31, 1972, 62 percent of the utilities reported an interest coverage ratio of 2.5 or more. By 1973, only 44 percent were in that category (see Table 12).

THE ROLE OF THE INDUSTRY IN CAPITAL MARKETS

Greater dependence on capital markets

Whereas all non-financial corporations, on the average, obtained 55 percent of their funds from internal sources in 1972, the far more capital-intensive electric utilities got only 31 percent of the funds they require in that fashion. It is pertinent to note that the bulk of the electric industry's relative modest internal funds are obtained via depreciation allowances. In striking contrast, the great bulk of the internal financing of other companies is through retained earnings; in fact, profits are their major single source of financing.

TABLE 11.—MINIMUM INTEREST COVERAGE REQUIRED BY INDENTURE (IN ELECTRIC RATE CASES SETTLED DURING 1971-73)

Required interest coverage	Number of cases	Percent of total
Less than 2.0	11	5
2.0	192	86
2.1 to 2.5	17	8
2.5 to 3.0	1	(1)
3.0 and over	2	1
Total	223	100

1 Less than 1 percent.

TABLE 12.—INTEREST COVERAGE AT TIME OF APPLICATION FOR ELECTRIC RATE CHANGE, 202 ELECTRIC UTILITY RATE CASES

Time period	Under 2.0	2.0–2.5	2.5–3.0	3.0 and over	Total
Jan. 1, 1971 to Mar. 31, 1972	5	22	14	31	72
Apr. 1, 1972 to Dec. 31, 1972	5	27	12	18	62
Jan. 1, 1973 to Dec. 31, 1973	4	34	10	20	68
Total	14	83	36	69	202

When we turn to the subject of external financing, we find that other companies generally obtain a substantial portion of their funds via bank loans and other short-term indebtedness, unlike the electric utilities.

Thus, the great and rather unique dependence of electric utilities on capital markets arises from a combination of factors:

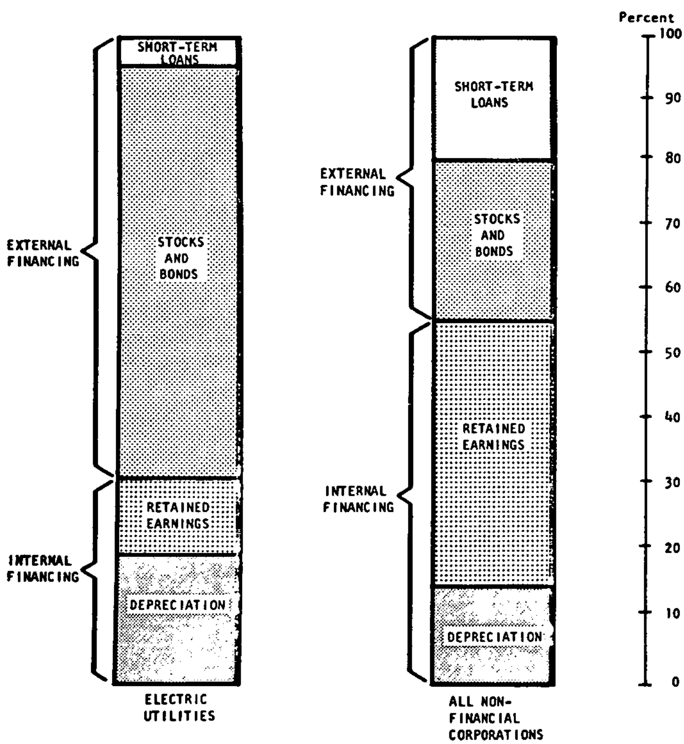
1. The highly capital-intensive character of the industry and hence its continual need for new capital.
2. The modest availability of retained earnings and hence the industry's dependence on external sources for financing its large capital programs.
3. The minor extent to which it uses, or could be expected to utilize, short-term financing for its long-term capital projects, and thus the great dependence on continually attracting new long-term capital into the industry.

Its proportion of total capital funds

Its high degree of capital intensity plus its reliance on external financing for the major part of its capital expansion have led to the investor-owned electric utility industry becoming a significant factor in the nation's capital markets and in the overall process of capital formation. This significance can be measured in a number of ways. Over the past 25 years, electric utilities have annually taken the equivalent of from 5 percent to 16 percent of all personal savings to finance their construction programs. Over the past decade this percentage has displayed a persistent tendency to rise. Over the period 1947–1972 the share of personal saving (measured on a national income basis) absorbed by investor-owned electric utility stock and bond sales averaged an unweighted 9.9 percent annually. During the five years 1968–1972, however, the average was 13.4 percent and the annual values have been rising steadily. Figure 3 illustrates the evolution of the electric utility industry's long-term external financing as a percent of personal savings.

Figure 2

GREATER DEPENDENCE ON CAPITAL MARKETS
(Sources of Funds in 1972)

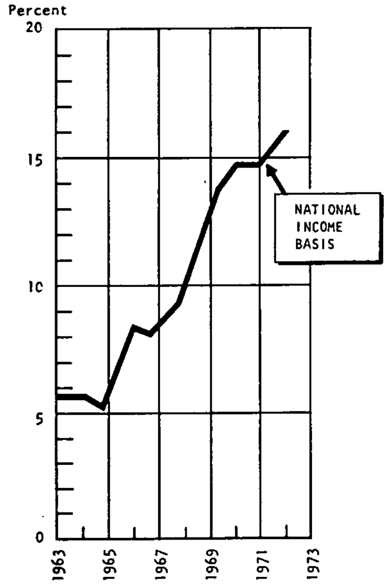


Another measure of the role of electric utilities in the nation's capital formation is the share of investor-owned electric utility expenditures in the total capital expenditures of all U.S. industries. Over the past decade the investor-owned electric companies have doubled their proportion of the annual creation of new plant and equipment in the United States, from 7.6 percent in 1964 to 15.0 percent in 1973 (see Table 13). Undoubtedly, some of this increase has been due to the unusually pronounced impact of inflation on the cost of construction, a factor which weighs heavily in utility capital expenditures. Also, the growing commitments to nuclear power, a very capital-intensive form of

Figure 3

NEW CAPITAL OF INVESTOR-OWNED ELECTRIC UTILITIES
AS PERCENT OF PERSONAL SAVINGS

1947 - 1973



power generation, have accounted for some of this increase. Another factor was the desire to develop sufficient reserve capacity to reduce the likelihood of "brownouts" and "blackouts" during periods of peak demand due to equipment failures.

TABLE 13.—CAPITAL OUTLAYS IN ELECTRIC UTILITIES AND OTHER INDUSTRIES

Year	All U.S. industries (billions)	Investor-owned electric utilities (billions)	Investor-owned utilities as percent of total U.S. industry
1964	$47.0	$3.6	7.6
1965	54.4	4.0	7.4
1966	63.5	5.0	7.8
1967	65.8	6.1	9.4
1968	67.8	7.2	10.6
1969	75.6	8.3	11.0
1970	79.7	10.2	12.8
1971	81.2	11.9	14.7
1972	88.4	13.4	15.2
1973	99.7	15.0	15.0

CHAPTER 3. THE FUTURE CAPITAL REQUIREMENTS OF THE ELECTRIC UTILITY INDUSTRY

WORKING ESTIMATE OF CAPITAL EXPENDITURES

For purposes of estimating the possible extent of external financing requirements of the investor-owned electrical utility industry in the period 1974–1980, the construction expenditure forecast to be used in the following analysis is a basic constant-dollar total of $103 billion. The moderate projections for 1979 and 1980 specifically reflect cutbacks in capital programs recently announced by several public utilities. An allowance is added to cover non-electric utility outlays by electric companies. When the figures are adjusted for a projected 7 percent annual rate of inflation, the result is a $141 billion total for 1974–80 in current dollars.

CAPABILITY OF THE INDUSTRY TO FINANCE ITS CAPITAL NEEDS

Estimated internal funds flow 1974–1980

This section of the report is devoted to developing estimates of the availability of internal financing for the electric utility industry through 1980.

Depreciation.—As is evident from data in the preceding tables, depreciation is the most important single source of internally generated funds for electric utilities. If the reduction in average depreciation rates is arrested and if construction expenditures grow at a decreasing rate through 1980, as is generally expected, depreciation would represent an increasing share of these expenditures. This will tend to reduce the need for increased external capital.

To forecast the flow of funds from this source through 1980, it is necessary to project total plant values for the period and make an assumption concerning the depreciation rate. Table 14 sets out the expected year-by-year net additions to gross plant. These are based on an assumed ratio of net additions to construction expenditures of 0.90.

Assuming that current depreciation rates in the neighborhood of 2.4 percent of total gross plant will be maintained for the balance of the decade, the internal funds flow represented by depreciation will rise from $3.6 billion in 1974 to $6.2 billion in 1980 (see Table 15).

Retained Earnings.—Earned surplus represents the second most important source of internal funding. The extent to which companies will be able to rely on retained earnings will depend on several factors, including rate relief and the trend of operating expenses. A conservative estimate would call for a growth in annual earnings retention of 7.2 percent a year, slightly below the average annual rate of increase realized over the period 1966–1973. Such an estimate would project retained earnings rising from $1.5 billion in 1974 to about $2.3 billion in 1980. Total earnings retained for reinvestment would equal $13.3 billion over the 1974–1980 time period (see Table 16).

TABLE 14.—PROJECTIONS OF ELECTRIC UTILITY GROSS PLANT

[In millions]

Year	Construction expenditures	Net additions to gross plant	Yearend gross plant
1974	$17,505	$15,755	$158,155
1975	16,370	14,735	172,890
1976	17,960	16,165	189,055
1977	19,605	17,645	206,700
1978	21,500	19,350	226,050
1979	23,260	20,935	246,985
1980	24,920	2,4430	269,415

TABLE 15.—PROJECTED DEPRECIATION CHARGES OF ELECTRIC UTILITIES

[In millions]

Year	Average gross utility plant	Depreciation at 2.4 percent of gross utility plant
1974	$150,280	$3,610
1975	165,525	3,975
1976	180,975	4,345
1977	197,880	4,750
1978	216,375	5,195
1979	236,520	5,675
1980	258,200	6,195
Total		33,745

TABLE 16.—PROJECTED RETAINED EARNINGS OF ELECTRIC UTILITIES

[In millions]

Year	Retained earnings
1974	$1,530
1975	1,640
1976	1,760
1977	1,885
1978	2,020
1979	2,165
1980	2,320
Total	13,320

Provisions for Deferred or Future Income Taxes.—Deferrals of income tax resulting from accelerated depreciation have become a significant source of the internal flow of funds since 1970. While still a small percentage of total requirements (about 3 percent of construction expenditures in 1973), these annual deferrals have been growing rapidly. Use of liberalized depreciation (or ADR) has enabled many companies to increase the benefits of using accelerated depreciation. It should be recognized that deferred taxes are only a source of funds for companies who are allowed to "normalize" tax incentives.

For purposes of this report, annual estimates of deferred taxes are assumed at 1 percent of the cumulative net additions to gross utility plant since 1969. On that basis, the annual total of deferred taxes will rise from $645 million in 1974 to almost $1.8 billion in 1980 (see Table 17).

Total Internal Funds Flows, 1974–1980—Table 18 summarizes the estimates of annual internal generation of investible funds from the three principal sources of depreciation, retained earnings, and deferred taxes. The total estimated availability of over $55 billion is an impressive sum, at least until compared to the anticipated capital requirements of the electric utility industry.

TABLE 17.—PROJECTED DEFERRED TAXES OF ELECTRIC UTILITIES

[In millions]

Year	Cumulative net additions to gross utility plant since 1969	Annual deferred taxes at 1.0 percent of cumulative net additions since 1969
1974	$64,325	$645
1975	79,060	790
1976	95,225	950
1977	112,870	1,130
1978	132,220	1,320
1979	153,155	1,530
1980	175,585	1,755
Total		8,120

TABLE 18.—PROJECTED INTERNAL FINANCING OF ELECTRIC UTILITIES

[Dollar amounts in millions]

Year	Retained earnings		Depreciation and amortization		Deferred or future income tax		Total	
	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
1974	$1,530	26.5	$3,610	62.4	$645	11.1	$5,785	100.0
1975	1,640	25.7	3,975	62.0	790	12.3	6,405	100.0
1976	1,760	25.0	4,345	61.5	950	13.5	7,055	100.0
1977	1,885	24.3	4,750	61.2	1,130	14.5	7,765	100.0
1978	2,020	23.7	5,195	60.8	1,320	15.5	8,535	100.0
1979	2,165	23.2	5,675	60.6	1,530	16.3	9,370	100.0
1980	2,320	22.6	6,195	60.3	1,755	17.1	10,270	100.0
Total	13,320	24.2	33,745	61.1	8,120	14.7	55,185	100.0

Extent of external funds required

For the 7-year period 1974–80, approximately 39 percent of estimated capital requirements of the electric utilities will be met by internal financing according to the estimates developed in this report, $55 billion out of over $140 billion (see Table 19). The remainder, nearly $86 billion, will have to be raised by attracting additional capital to the industry. Another way of looking at the situation is that, for a regulated utility, the internally generated sources of funds are a relatively fixed percentage of existing plant. Depreciation is directly a function of the capital stock and income is based on rates geared to the "rate base," which is closely related. Hence, substantial increases in capital spending generally require added use of external financing via sales of stock and bonds.

TABLE 19.—PROJECTED EXTERNAL FINANCING OF ELECTRIC UTILITIES

[Dollar amounts in millions]

Year	Construction expenditures		Internally generated		Externally financed	
	Amount	Percent	Amount	Percent	Amount	Percent
1974	$17,505	100.0	$5,785	33.0	$11,720	67.0
1975	16,370	100.0	6,405	39.1	9,965	60.9
1976	17,960	100.0	7,055	39.3	10,905	60.7
1977	19,605	100.0	7,765	39.6	11,840	60.4
1978	21,500	100.0	8,535	39.7	12,965	60.3
1979	23,260	100.0	9,370	40.3	13,890	59.7
1980	24,920	100.0	10,270	41.2	14,650	58.8
Total	141,120	100.0	55,185	39.1	85,935	60.9

PROSPECTS FOR A LOWER GROWTH RATE IN ELECTRICITY USAGE

During the past two decades, the consumption of electricity in the United States has risen at an annual rate of 7.4 percent, from 443 billion kilowatt-hours in 1953 to 1,849 billion kilowatt-hours in 1973. For most periods, except during the boom of the 1960's, electricity usage has grown more than twice as fast as the economy as a whole, reflecting in part the fact that the price of electricity was declining sharply relative to all prices. The record of more recent months, however, shows the possibility of a shift in the historical trend.

Relationship between Rates and Usage

Consumption of electricity began running below the level of the previous year almost immediately upon the imposition of the oil embargo in the fall of 1973. This decline in usage, to some extent, reflected the public reaction to the government's efforts to foster voluntary conservation. It subsequently was reenforced by the sharp rise in utility rates, although we cannot measure the precise impact. However, by March 1974, even before the embargo was lifted, usage of electricity began exceeding year-ago levels. The trend since then has been erratic. June power consumption declined from the level of June 1973, but that may reflect both an unusually strong month last year and unusually cool weather this year with an attendant dampening effect on air conditioning usage.

This fluctuating pattern may suggest that voluntary measures are difficult to sustain beyond periods of immediate crisis. Also, the impact of price on demand patterns may take considerable time to unfold. In the short run, some economists report that the elasticity of demand for residential users of electricity is quite low, between —0.1 and —0.2. This means that a 10 percent increase in utility rates will reduce usage by only 1–2 percent.

Over the long run, however, demand may be quite elastic. Professor Dale Jorgenson of Harvard University has estimated a long-run "elasticity" of demand for electricity at —0.62; that is, a 6.2 percent decline in kilowatt-hours consumed for every 10 percent rise in prices. The economic staff of the Federal Reserve Bank of San Francisco reports that some studies indicate a long-run elasticity of demand of —1.0 for residential users of electricity, as does a study by Professor Hendrik Houthakker of Harvard University and several associates. A recent report by the Oak Ridge National Laboratory found elasticities for commercial and industrial users in the —1.5 range.

However, a paper by Roger Carlsmith, Associate Director of the ORNL-NSF Environmental Program at Oak Ridge adds the following "word of caution":

"We also find that there is a time delay of 6–10 years in the response to price changes. Thus one cannot expect electricity price rises to be a near-term solution to the problem of supply shortages."

If measures of price elasticity for electricity are uncertain, even less work has been done in quantifying measures of cross elasticity with other fuels, such as oil and natural gas. It may well be that price elasticity for all energy is rather low while cross elasticities, over the longer run, are rather high. If this is the case, then to properly predict demand for electricity one would also need to predict the price and subsequent demand for other energy sources as well.

As a general proposition, economists see electrical energy as a commodity subject to the influences of supply and demand, which means a sensitivity to price. Many long-term projections by financial institutions and industry sources now in use were prepared prior to the recent large increases in rates. It could well be that these forecasts overstate future electricity usage.

Energy growth expanded rapidly in the past two decades, in part because real energy prices were declining (that is, rates were going up more slowly than the general price level). Between 1951 and 1971, real electricity prices were reduced by 43 percent, encouraging users to substitute energy for labor and material, which were rising faster in price. Now that energy prices are rising faster than labor and materials, some reverse substitution may dampen energy demand.

Chapter 4. The Role and Importance of Utility Rates

THE NATURE OF UTILITY REGULATION

Table 20 contains the results of a special survey conducted by the Edison Electric Institute covering 210 electric rate cases which were settled during the three-year period 1971–1973. The very considerable variation in the overall rates of return which are allowed to individual companies is apparent, ranging from less than 6 percent to over 9 percent.

Table 21 contains corresponding information for 181 of the cases where information was available on the return on common equity which was granged by the regulatory commissions. Here, even more substantial variations are visible.

TABLE 20.—VARIATIONS IN ALLOWABLE RATES OF RETURN (IN ELECTRIC RATE CASES SETTLED DURING 1971–73)

Less than 6 percent	12
6 to 7 percent	34
7 to 8 percent	112
8 to 9 percent	59
9 percent and over	2
Total	219

TABLE 21.—RETURN ON COMMON EQUITY GRANTED (IN ELECTRIC RATE CASES SETTLED DURING 1971–73)

Less than 6 percent	2
6 to 8 percent	4
8 to 10 percent	11
10 to 12 percent	66
12 percent and over	98
Total	181

Without prejudging the decisions of any specific commission, it is clear that they vary very substantially in the pattern of their decision making, as well as in the manner in which they apply rates of return. Some commissoins tend to grant higher returns to their electric utilities that do other commissions, and the differences cannot be explained by variations in capital structure. On reflection, that is likely to be the result of decentralized regulation responding to a variety of economic, politial, geographic, and social circumstances.

REGULATORY LAG

The aspect of regulation which appears to have provoked the greatest amount of interest during the recent period of rapidly rising utility costs has been the delay or "lag" involved in regulatory commissions acting on requested changes in electricity rates.

TABLE 22.—BACKLOG OF ELECTRIC UTILITY RATE CASES

Quarter ending	Number of cases pending	Total dollar value of increases pending (millions)
Mar. 31, 1970	45	$512
June 30, 1970	46	615
Sept. 30, 1970	47	435
Dec. 31, 1970	59	679
Mar. 31, 1971	71	939
June 30, 1971	86	986
Sept. 30, 1971	105	1,237
Dec. 31, 1971	99	1,157
Mar. 31, 1972	96	938
June 30, 1972	104	1,067
Sept. 30, 1972	102	1,317
Dec. 31, 1972	99	1,123
Mar. 31, 1973	96	1,059
June 30, 1973	123	1,572
Sept. 30, 1973	112	1,283
Dec. 31, 1973	137	1,656
Mar. 31, 1974	144	2,052
June 30, 1974	169	2,678

The resultant problem of regulatory lag has become one of the major focal points of concern in financing electric utility expansion. This lag between the time a utility files a request for a change in rates and the time a change is granted has been aggravated not only by the number of increases being filed but by the increasingly extensive hearings associated with each case. This latter complexity has increased in turn because of the growing number of interventions by environmentalists, consumer advocates, and others.

One measure of the increasing dimensions of the "backlog" problem can be found in the data on the number and dollar value of increases pending at the end of each quarter for the period 1970 through the second quarter of 1974. As shown in Table 22 there has been a fairly steady and substantial increase in the backlog of pending rate cases, measured both in terms of number of cases and total amount of rate changes requested.

Rising backlogs mean increasing delays in getting the average case completed. Data on 211 final rate case decisions made by state and local regulatory bodies during the three years 1971–1973 show that less than 30 percent of the cases were concluded within 6 months of the initial filing. About 47 percent were completed between 6 months and one year. Nearly one-fourth required more than one year. One-third of those cases involving lags of more than one year required more than 18 months before a final decision was reached (see Table 23).

The length of the lag appears to be increasing. An analysis of final rate case decisions made in the year 1973 alone indicates an increase in the percentage of cases requiring more than one year for settlement with nearly 30 percent in this category. More than half of the latter involved lags greater than 18 months. Perhaps a more fundamental finding from the data is the very substantial variation in the length of the regulatory process that exists from state to state, from utility to utility and from one time period to another.

TABLE 23.—VARIATIONS IN REGULATORY LAG IN ELECTRIC UTILITY RATE INCREASES, 1971-73 (TIME FROM FILING OF APPLICATION TO FINAL ORDER FROM COMMISSION)

Date of final order	Number of cases and percent distribution													
	0 to 6 months	Percent	6 to 12 months	Percent	12 to 18 months	Percent	18 to 24 months	Percent	24 to 30 months	Percent	Over 30 months	Percent	Total	Percent
1971	13	24	27	50	13	24	1	2					54	100
1972	26	31	41	49	12	15	3	4			1	1	83	100
1973	21	28	31	42	10	14	8	11	4	5			74	100
Average lag (percent)	28		47		17		6		2					100

Interim increases

One method of compensating for lengthening delays between initial filings and final decisions is the granting of interim or temporary increases. In the 211 decisions covered by the above analysis, 51 involved interim increases. The survey data revealed a growing use of this procedure. While only 13 of the rate cases settled in 1971 had involved interim increases, 18 of those completed in 1972 had such increases, as did 20 of those in 1973. Throughout the three-year period for those cases where interim increases were permitted, the average delay before an interim increase was granted was just under 5 months from the initial filing.

Automatic adjustment clauses

Certain costs of electric utility operation, subject to frequent changes, are essentially out of the utility's power to control, at least in the short run. Some of these costs represent significant portions of utility expense. To handle this problem, many regulatory bodies permit utilities under their jurisdiction to use automatic adjustment mechanisms which reflect, with relatively short delays, the increase (or decrease) in the particular expense in question. The use of these automatic adjustment clauses in effect thus reduces regulatory lag with regard to the uncontrollable costs which are covered by these clauses.

Among the types of adjustment clauses in use are those for taxes, the cost of power purchased from other utilities, and fuel costs. The latter two have become increasingly important in recent years as fuel costs have escalated rapidly and the need to exchange power among utilities has increased because of delays incurred in the scheduled addition of new capacity. The fuel adjustment clause is the most important one for many utilities and is most frequently alluded to in public discussions of automatic provisions.

Currently, about three-fourths of all investor-owned utility kilowatt-hour sales to ultimate customers are covered by fuel adjustment clauses. The extent of their use varies from state to state, however. In 43 states and the District of Columbia at least some of the rates of investor-owned companies are accompanied by such riders. In some instances, their use is restricted to industrial and commercial rates while in other cases all rates are covered. Differences also exist with regard to the method of calculating the adjustment charge. Some utilities base the adjustment on fuel costs incurred the previous month, others on the average cost cf the two previous months, and still others use even longer periods.

RELATIONSHIP OF CURRENT RATE INCREASES TO FUTURE COSTS

It is important to recognize that the so-called regulatory lag as it relates to the adjustment of permissible earning rates for utilities is not an accident of history. The regulatory lag which receives so much attention these days has served a useful function over the years in accommodating a range of earnings opportunity within which utility management is challenged and motivated to perform efficiently. The fact that a company may have to wait for an extended period of time before rates are adjusted upward to reflect special circumstances also provides a strong incentive to management to eliminate inefficient operations. By the same token, during periods in which technological innovations are reducing costs, management may enjoy an extended period of above average profitability before regulatory authorities require downward rate adjustments.

Bond ratings and utility rates

It may be difficult for individual users of electricity to see the relationship between utility rates and something so technical as bond ratings. After all, why should they really care what happens to the bondholders? Analysis shows that there are very good reasons. The basic answer is that interest on those bonds is one of the rising costs that are forcing utilities to apply for rate increases.

When a utility's bond rating drops, the amount of interest it has to pay on its new bonds rises. For example, when Union Electric sold $70 million of bonds on February 5, 1974, it had to pay an interest charge of 8.29 percent (its bond rating was a moderate one, single-A by Standard and Poor's and double-A by Moody's). On the day before, a company with a stronger bond ratting (AA), Public Service of Indiana, sold its bonds at a cost of 8.03 percent. Spread out over the 30-year mortgage period, Union Electric's higher interest will cost the utility—and ultimately its customers—an additional $5,250,000.

VARIATIONS IN REGULATORY AND UTILITY PRACTICES

As shown in earlier sections of this report, there are very substantial variations in the pattern of decision making by utility regulatory commissions in different parts of the country. An examination of these variations provides useful insights into possible changes in regulatory or company practices which may help to meet the financing requirements of the utilities through means other than general rate increases.

Utility billing practices

One area of substantial variation among utilities is in the way customers are billed for services, particularly in the case of late payments. An April 1974 survey of billing practices of 90 electric utilities obtained a variety of responses. While 40 of them do not have any charge for late payments, the other 50 follow many different ways of adding a penalty or interest to the bill or offering a discount for prompt payment. As shown in Table 24, the interest charges range from a low of 6 percent to a high of 18 percent, where such charges are made.

Only 17 of the utilities reported that all classes of customers were charged for late payment. Seventeen other utility companies said that government agencies were not charged, and five others excluded both residential and governmental users. Two utilities only levied late charges on large commercial and industrial users, while the late charges of two other utilities covered all customers except large general service and industrial users. There is also an important equity aspect to this relatively mundane question of billing.

The reluctance of some regulatory commissions to permit utilities to charge penalties for late payment means that customers who pay their bills promptly are unfairly bearing a portion of the cost of the added working capital to be raised by the utility to compensate for the lack of revenue from late-paying customers.

TABLE 24.—LATE PAYMENT CHARGES BY 90 UTILITIES, APRIL 1974

Penalty for late payment (addon to base rate)	35
Discount for prompt payment (deduction from base rate)	8
Interest charge:	
6 percent	3
12 percent	1
18 percent	3
No late payment charge	40
Total	90

Automatic cost pass-throughs

To deal expeditiously with the frequent increases in the cost of fuel purchased by electric utilities, many regulatory commissions have authorized companies to add an automatic adjustment to utility bills to cover such increased and relatively uncontrollable costs. Table 25 shows the rapid growth in the use of these automatic clauses. Whereas less than two-thirds of settled rate cases contained fuel cost pass-through clauses covering 90 percent or more of the kilowatt-hours sold during 1971 and early 1972, these provisions had become almost universal by late 1973.

The use of these automatic devices tends to reduce regulatory lag, but not to eliminate it. Some commissions require utilities to use the FIFO method (first in, first out) to measure changes in fuel inventories. With a 60-day-or-greater stockpile, a utility may thus have to wait two months or more before its added fuel costs become eligible for inclusion in the pass-through. There is another lag—often 1–2 months—between the time that increased fuel costs are allowable and the time that they actually show up in added billings. Thus, a 3–4 month lag is customary even with the use of supposedly automatic pass-through mechanisms.

TABLE 25.—COVERAGE OF FUEL CLAUSES—PERCENT OF KILOWATT-HOURS (IN ELECTRIC RATE CASES SETTLED DURING PERIOD)

Time period	Percent					
	0–25	26–50	50–75	76–90	90–100	Total
Jan. 1, 1971 to Mar. 31, 1972	6	6	11	3	46	72
Apr. 1, to June 30, 1972	1	1	1	0	18	21
July 1, to Sept. 30, 1972	0	0	1	0	15	16
Oct. 1, to Dec. 31, 1972	0	2	3	2	19	26
Jan. 1, to Mar. 31, 1973	0	0	4	0	16	20
Apr. 1, to June 30, 1973	2	0	2	4	13	21
July 1, to Sept. 30, 1973	3	0	1	0	17	21
Oct. 1, to Dec. 31, 1973	0	1	1	0	18	20
Total	12	10	24	9	162	217

TABLE 26.—TYPES OF RATE BASES USED IN ELECTRIC RATE DECISIONS, 1971–73

Original cost	176
Fair value	61
Both	3
Total	240

Rate bases

The base on which utility rates is determined is of course one of the key factors in the regulatory process. Traditionally, most state commissions have used the original cost of the applicable company investments to estimate the rate base.

As shown in Table 26, however, in a modest number of cases, the commissions have used a replacement or "fair-value" basis. In a period of rapid inflation, the latter approach is likely to yield a higher base for rate making. Although this report is not the place for a detailed analysis of the two alternatives, it should be noted that replacement cost may come closer to the economic notion of "opportunity costs."

Interim rates

In some states, interim rate increases may be granted while a rate increase is being considered by the regulatory commission; typically, the interim rate is lower than the request being considered. This clearly is an effort to reduce the length of regulatory lag. In 18 percent of the cases surveyed, interim increases were granted see (Table 27).

A related approach is for the commission to grant a temporary approval of the requested increases, with the proceeds held under bond. Thus, if the commission ultimately rejects the increase or approves a lesser amount, all or a portion of the proceeds must be refunded to the customers. As shown in Table 28, this procedure was followed in 11 percent of the cases surveyed.

Treatment of tax incentives

The benefits of Federal tax incentives are often offset, in the case of public utilities, by the actions of state regulatory authorities. For example, many utilities are in effect required to ignore the rapid write-offs of capital outlays permitted for Federal income tax purposes and to "flow through" the tax savings. This results in higher reported earnings and in lower cash flow to finance new outlays.

TABLE 27.—INTERIM RATES IN EFFECT WHILE CASE IS IN PROGRESS (IN ELECTRIC RATE CASES SETTLED DURING 1971–73)

In effect	48
Not in effect	215
Total	263

TABLE 28.—RATES IN EFFECT UNDER BOND WHILE CASE IS PENDING (IN ELECTRIC RATE CASES SETTLED DURING 1971-73)

In effect	30
Not in effect	234
Total	264

In recent years, many commissions have permitted utilities to switch from "flow through" to "normalization," that is tó follow the procedures used in industry generally. But as shown in Table 29, in over half of the cases, utilities are still required to use the "flow-through" method for all or at least part of the Federal tax incentives.

Forward looking test periods

Regulatory commissions generally set utility rates on the basis of costs incurred during some recent past period of time, which is referred to as the "test period." Some commissions have been experimenting with the use of estimated future costs as a basis for fixing rates. In July 1973, the Federal Power Commission issued order No. 487 providing for a twelve-month test period beginning as late as the date when the increased rates are proposed to go into effect. The order covers wholesale rates where the proposed increase is in excess of $1 million; for smaller increases, the use of a future test period is optional. Historical data for the preceding 12-month period will also be considered, but primarily to check the reasonableness of the projected figures.

Although there is always some reluctance to base decisions on forecasts of future events, it should be noted that the future test period used by some commissions is quite short when compared to the planning period for electric utilities. The companies are expected to invest very substantial sums in equipment which is to be used to meet demands which are anticipated to arise over a period of several decades.

Changes in utility rate structures

In the past year considerable interest has developed in the possibility of discouraging the use of electricity through revising the current "declining-block" rate schedule whereby larger users of power typically pay lower rates for each "block" they use. The current practice is defended on the basis of the underlying economics—the total cost per kilowatt-hour tends to decline with volume, as many items of fixed cost are spread over a larger number of units; thus price is related to cost of service. To some extent, however, a considerable flattening of electric rates is occurring with the growing importance of proportional "fuel-adjustment" charges whereby utilities pass on the added cost of the fuel they purchase. Further flattening of block rates for large industrial and commercial customers may result from the sharp rises in generation and transmission costs.

There is precedence in other parts of the economy for discouraging usage in peak periods, when production is more costly, and to encourage off-peak use when the cost of production is very low. Movie houses, parking lots, and other kinds of businesses set their prices according to the time of day in order to spread the use of their facilities in the most efficient pattern.

Telephone companies do this by charging higher rates for long-distance calls in the daytime and thereby encouraging night-time, off-peak use of their facilities. Similarly, many airlines offer lower "night-owl" rates. Electric utilities have taken limited steps in this direction. The Union Electric Company charges lower rates for dusk-to-dawn lighting. It seeks to promote electric heating by bargain rates in an effort to offset the summer air-conditioning peaks (ironically, summer air conditioning was originally encouraged by the utilities when their peaks resulted from winter heating demands).

Higher summer rates may also be viewed as an attempt to deal with the problem that, under current rate schedules, the higher usage represented by air conditioning is charged a lower than average rate, while the cost of installing the added capacity to provide the extra power is higher than the cost of providing basic electric power.

TABLE 29.—TREATMENT OF TAX INCENTIVES (IN ELECTRIC RATE CASES SETTLED DURING 1971–73)

Normalization	113
Flow through	98
Both	35
Total	246

Another suggestion for change in the structure of utility charges is to "invert" the rates, eliminating the discounts now given to large users and, in order to foster conservation, increasing a user's unit charges as usage rises. Such a change, it is frequently argued, would constitute a fundamental departure from the time-honored principle that prices should reflect costs. It is obvious that it costs a utility more to bring power to small separate residences or retail stores than to one large industrial plant, but it is not inevitable that existing rate differentials exactly match these cost differences.

CHAPTER 5. PROPOSED CHANGES IN PUBLIC POLICY: GOVERNMENT CREDIT GUARANTEES

The traditional response to prospective difficulties in financing the capital programs of electric utilities is in terms of increasing the general rate structure. As shown in an earlier chapter, that is currently the preferred solution on the part of many authorities.

Yet, recent rate increases have been so substantial and at times public opposition to further rate increases so vehement, that a number of people have urged new approaches. It should be realized that these suggested innovations are not generally described as complete substitutes for rate changes. Rather, they are often presented as a means of slowing down the rising price of electricity.

This chapter is devoted to an examination of one group of those proposals—suggestions to lighten the financing burdens of electric utilities through government credit guarantees. The following chapter presents and analyzes other proposals for easing the financial pressures on electric utilities. A specific plan for such guarantees has been advanced by Willian G. Rosenberg, chairman of the Michigan Public Service Commission. In its essence, the Rosenberg approach is to have the Federal government guarantee the interest of the bonds issued by electric utilities. The Federal support is also seen as permitting the utilities to more highly leverage their financial structures, to issue a larger proportion of bonds to stock than is currently the case. His expectation is that the lower interest rates which the utilities could pay on these bonds would reduce the very substantial pressures for rate increases that are now being felt by the Michigan Public Service Commission and by its counterparts throughout the nation.

Chairman Rosenberg contends that such a system of Federal guarantees would reduce the cost of capital by enabling electric utilities both to issue bonds at lower rates of interest and to use more debt and less equity in their capital structures. Thus, savings would result from two sources: 1. lower interest payments and 2. a substitution of tax-deductible interest for non-deductible dividend payments.

This phenomenon occurs for a variety of reasons. The total supply of funds is determined by household and business saving and the ability of banks to increase the money supply. The normal response of financial markets to an increase in the demand for funds by a borrower, such as is represented by a Federal credit program, is an increase in interest rates so as to balance out the demand. for funds with the available supply. But the Federal government's demand for funds are "interest-inelastic" (the Treasury will generally raise the money that it requires regardless of the interest rate)..Thus, weak and marginal borrowers will be "rationed" out of financial markets in the process, while the Treasury and other borrowers pay higher rates of interest. To the questions "Who will be rationed out? Who will be the new disadvantaged in the credit market?", the literature provides clear answers. To quote Henry Kaufman:

"It is unlikely to be the large well-known corporations or the U.S. Government. It is likely to be some state and local government, medium-sized and smaller businesses, some private mortgage borrowers not under the Federal umbrella, and some consumer sectors. . . . This is bound to contribute to additional economic and financial concentration in the United States."

It is clear that the proposed program of Federal guarantees of utility bonds would possess similar characteristics as existing Federal credit programs. It would do nothing to increase the total amount of saving in the economy which provides the basic pool of investment funds. Moreover, to the extent that the government guarantees enable utilities to obtain a larger share of available capital funds, the results would be two-fold:

1. To elbow out of credit markets weaker and "unprotected" borrowers such as consumers, homeowners, small businesses, school districts, and smaller counties, cities, and other units of local government.

2. The diversion of investment funds from these other sectors to utilities would require an increase in interest rates. Thus, some of the anticipated saving in interest costs to the utilities from the government guarantee would not materialize, and borrowing costs to other borrowers would tend to rise.

IMPACTS ON THE FEDERAL GOVERNMENT AND ON FEDERAL TAXPAYERS

One impact of the Rosenberg plan is clear and negative: to the extent that the guarantees were successful in permitting utilities to shift from stock issues to bond issues, the resultant increase in tax-deductible interest payments would reduce the payments of income taxes by utilities to the Treasury. Nothing in the proposal would generate any offsetting savings in Federal spending. Rather, the plan calls for the Treasury meeting utility interest payments if the companies are unable to do so and the guarantee fund is exhausted.

Thus, the Rosenberg plan would either result in a larger budget deficit—which would exacerbate the inflationary pressures which are the source of so much of the industry's present financial difficulties—or it would require adding to the tax burdens of all other taxpayers.

Impacts on Government bond issues

As Federal guarantees are extended to more and more private borrowers, an ever larger proportion of the nation's debt consists of Federal credit. In order to entice a rising share of available savings, some increase would be expected in the interest rates paid on such debt. That is, if—in the absence of the Rosenberg plan—total Treasury and government-guaranteed borrowing in a given year were $50 billion, then, with the Rosenberg plan, total Federally assisted borrowing would rise to $70 billion.

It is reasonable to anticipate that a higher rate of interest would have to be paid to attract $70 billion of saving to government credit activities than $50 billion.

If the Federal government were to guarantee all public utility debt, the resultant quick and massive expansion of the size of the government debt market is likely to result in sharp increases in the interest rates necessary to attract a new body of investors to government securities. Even if the new rates are below those now paid by utilities, they likely will be above those now paid by the Treasury. Hence, the advantages that would accrue to the utilities and their customers would be offset by the higher interest costs paid by the Treasury and thus financed by all taxpayers and the general public.

As a general proposition, it would be expected that government-guaranteed debt would have a lower interest rate than ordinary utility bonds. But, as stated by one authority, "There is some reason to doubt, however, that this would actually be very substantial in effect." Herman G. Roseman, vice president of National Economic Research Associates, points out that the yields on Treasury bonds seem to have declined relative to utility bonds at least in part because of the decline in the outstanding volume of Treasury bonds. "There is no reason to think that a government-guaranteed utility bond would be regarded as a substitute for a Treasury bond—which has a very high degree of marketability—and that it bear the same rate as a Treasury bond."

Support for this position is obtained by examining existing programs of Federal guarantees of the credit of private corporations. In the case of the railroads whose loans were guaranteed by the Federal Government during the period 1959–63, the interest rates that they paid were substantially higher than the rates paid by the Federal government as well as those of public utilities, who were operating without the benefit of a Federal guarantee.

A more recent program of Federal guarantees covers the financing (of American-built ships. At the time of the offering of the bonds—which were clearly labeled "United States Government Guaranteed Ship Financing Bonds" —they were priced to yield 7.9 percent at a time when Treasury bonds were yielding about 7 percent and utility bond yields averaged about 8 percent.

Chapter 6. Proposed Changes in Public Policy: Other Prospects For Change

Many other proposals, in addition to suggestions for Federal credit guarantees, have been offered in order to deal with the substantial financial pressures facing the electric utility industry. These vary from large tax subsidies and other Federal assistance limited to electric utilities to generalized incentives to promote investment throughout the nation. A great many of the proposals center on changes in the structure of utility rates and in the system of regulation. This chapter attempts to examine representative proposals in each of these categories.

CHANGES IN UTILITY REGULATION

In a letter sent to all 50 governors in early July 1974, Federal Energy Administrator John Sawhill called for an overhaul of state utility regulations to make them more responsive to national energy policy. He specifically urged that utilities be allowed an automatic "pass through" of fuel and operating costs. At present, at least some portion of higher fuel costs can be passed through automatically in most states. No state, however, has authorized an automatic procedure for passing through total operating costs.

Regulatory lag

If all regulatory commissions were to adopt the practices of the most advanced commissions, a very considerable overall reduction could be achieved in regulatory lag in the United States. Such reduction in administrative delay—and in the high cost of many of the administrative proceedings that are involved—would surely contribute to an ease in the financial pressures now experienced by electric utilities.

Future test years

A number of regulatory commissions are moving to the use of future test years. The chairman of the Missouri Public Service Commission, James F. Mauze, was quoted as stating late in June 1974:

"In a short time, we hope to be using a 12-month future test year in all cases. We want the best current information obtainable, and we have been working on ways to get it and make the best use of it."

This approach is designed to avoid the "revolving door" phenomenon whereby, within months of a decision to grant a rate increase, a utility returns for another rate increase because of further increases in costs. Mr. Mauze described this as "an incredibly inefficient way to regulate. It wastes our time, the utility's time, and the resources of the rate payers and investors . . . In the current inflationary state of the economy, sound regulation requires that rate making be forward looking and not tied to outdated information."

A change in the investment base

A number of investment analysts have proposed a change in the method in which regulatory commissions estimate the rate base for rate-making purposes (the lower the base, the higher percentage return is shown by any given level of earnings). Specifically, construction work in progress generally is not included in the rate base.

A rough estimate of the amount of such construction work in progress on the part of investor-owned electric utilities is $25 billion. The total is likely to increase substantially in the future because of growth, longer construction time for nuclear power plants, and inflation.

Charges for late payments

Unlike companies in most other lines of business, many utilities are not authorized to charge interest or penalties for late payment of bills (as shown in

Chapter 4). This practice further increases the borrowing needs of the utilities without providing any offsetting income. In retail trade, in comparison, extra charges for late payments are nearly universal.

Changes in rate structures and company practices

As discussed in Chapter 4, many authorities advocate changes in utility rate structures as a means of reducing peak-load demands and thus decreasing somewhat the need for further capacity on the part of this most capital-intensive industry. A review of recent statements by executives of some electric utilities conveys an impression of great reluctance to follow a course of action which would dampen down the demand for their industry's product. Although that is a very natural reaction—if you truly believe that electricity is a good thing, then more would seem to be better than less—that approach does not seem to be in accord with current national efforts to conserve energy—nor with the rising long-run average costs facing the industry.

The demand for electrical power is uneven, a factor which tends to increase costs. In most regions, there is a summer seasonal peak, as well as daily peaks during the mornings and late afternoons. Typically, there are large slack periods at night and in the early morning.

During the slack periods, the most efficient generating plants are operating. During the peak periods, the most inefficient generating units are brought on stream. The average load factor for the electrical utility industry in 1973 was 62 percent, with very substantial variations among individual companies. Thus, much of the equipment was underutilized. As a public utility, of course, each company in the industry has to maintain sufficient equipment to meet peak demands.

However, if the electrical load could be made more level, the most efficient units could be operated to capacity most of the time and the relatively inefficient ones could be used to the minimum extent possible. Since electricity cannot be stored directly, if the efficient units were used to capacity during the off-peak hours, there would be a net saving in the total energy consumed.

There may be important changes which the companies themselves can make. Many of the managements are already doing so. For example, advertising and related promotional activities could be fundamentally redirected. Rather than urging uses such as air conditioning which tend to heighten the peak-load problems of the industry and thus accentuate its need for capital, consumers could be encouraged to rely more heavily on off-peak uses of electricity, such as space heaters and hot water heating. The result would be a more economical use of existing capacity and thus a dampening of the pressures for rapid rate increases. Rather than a ban or severe restrictions on utility advertising, as has been done in some states, what is needed is a positive program of customer education on how to use electricity more efficiently with especial emphasis on curbing use during peak periods.

A prime candidate for conservation efforts is air conditioning, a relatively small but strategic usage; air conditioning is a major contributor to the summertime peak load for utilities. An indirect method of dampening such demands, adopted by some companies, is to charge a higher summer rate. Home and office insulation might make an important contribution here, as well as in the space-heating field.

DIFFERENTIAL TAX BURDENS

As might be expected, some individual utility executives have advocated government tax subsidies as a way of easing their financial pressures. Although such action would require Congressional approval, it would not be subject to the close and continuing scrutiny that is normally given to appropriation bills providing for direct payments from the Treasury. The economic impact of course is the same. A dollar less in tax receipts increases the Federal budget deficit as surely as does a dollar of additional direct expenditure. There does not appear to be any economic justification for exempting electric utilities from paying their full and fair share of taxes.

What may be a more relevant question is whether the existing tax burden on the electric utility industry is fair. Even the most cursory examination of the subject reveals that this desirable situation is not always the case. At the Federal level, utilities only receive a 4 percent investment tax credit, whereas all other companies generally are allowed a 7 percent credit for their capital investment. Table 30 contains the Treasury Department's estimates of the revenue cost of liberalizing the investment credit for a sample of 39 large electric utilities. If the credit had been raised from 4 percent to 7 percent in 1972, the payments of Federal corporate income tax by the 39 companies would have been $63 million less than they actually were (a reduction from $537 million to $474 million). Because the credit is limited to 50 percent of taxable income, the bulk ($122.5 million) of the increased credit could not have been used in 1972 and would have been carried over into future years.

If the income limit was raised from 50 percent to 100 percent, the Federal tax payments by the 39 electric utilities would have been reduced by $140.5 million and only $44.9 million of the credit would have been unused and carried over.

In an earlier period, it may have been the case that electric utilities could be counted on to make a high level of investment in new plant and equipment without as generous incentive as is received by other companies. In the present circumstances, however, that approach appears to be outmoded and based on unrealistic assumptions. Placing electric utilities on a parity with other industries in the tax incentives received for new capital investments would seem to be highly desirable. Moreover the provision limiting such credit to 50 percent of net income benefits companies with high earnings and penalizes utilities with low net income. It also encourages using "middlemen" (leasing companies) in order to gain some portion of the tax credit through indirect and hence more costly means.

TABLE 30.—REVENUE COST OF LIBERALIZING INVESTMENT TAX CREDIT FOR 39 ELECTRIC UTILITIES IN 1972

[In millions]

Category:	Impact
Raising the credit from 4 to 7 percent:	
Increased credit in 1972	$63.0
Carryover to future years	122.5
Raising the credit to 7 percent and raising the income limit to 100 percent:	
Increased credit in 1972	140.5
Carryover to future years	44.9

High tax burdens of investor-owned electric utilities

It is primarily at state and local government levels, however, that the disparity between the tax treatment of investor-owned utilities and other taxpayers is apparent. The relatively high state and local tax burdens borne by electric utilities can be traced back to relatively recent periods when the underlying circumstances were quite different than at present. In a standard work on public utility economics written in 1947, Professor Emery Troxel pointed out how and why local jurisdictions levied heavy taxes on utilities:

"Being large, frequently prosperous, and handy sources of tax revenue, corporations are taxed more heavily than property owners and proprietorship businesses. And public utility companies, which are quasi-public enterprises and often have large and quite stable earnings, are taxed even more heavily than other corporations . . . Local governments, indeed, often preferred to eliminate unreasonable earnings with franchise taxes and franchise obligations instead of price reductions or new service obligations."

Table 31 lists those cities which were reported in the *Municipal Yearbook* for 1972 as taxing public utility receipts but not having a general sales tax. Some local governments that have both forms of taxation may levy higher rates on utilities than on other sales, but data are not readily available.

The extent to which many local governments have come to depend on the capital-intensive electric utility industry for property tax revenues is a closely related aspect of the problem. For example, when the New York State legislature began to consider easing the capital burdens of Consolidated Edison by taking over some of its facilities, New York City officials pointed out that the city stood to lose about $45 million a year in real estate tax receipts.

OTHER PUBLIC POLICY PROPOSALS

A final category of proposals which have been advocated to assist financing electric utilities consists of those changes in public policy which are not limited to a single industry, but would help to reduce the rate of inflation and otherwise increase the availability of funds for saving and investment.

Clearly, more effective use of monetary, fiscal and other macroeconomic policies designed to deal with the general inflationary situation facing the United States would help the electric utility industry. However, there is such ample reason to support these efforts independent of their effects on a single industry that it would not seem to be fruitful to further develop that theme in this report.

Reducing Government credit subsidies

On the other hand, there is one aspect of general economic policy which, on the basis of this study as well as other considerations, would seem to be worthy of much greater public attention—the need to promote an overall economic climate which will yield a larger flow of private saving to finance the rapidly increasing investment requirements facing the nation. As the analysis of the proposed Federal credit guarantees brought out, attempts to provide the electric utilities with a larger slice of an inadequate "pie" of investment funds will be self-defeating.

TABLE 31.—SPECIAL LOCAL TAXES ON PUBLIC UTILITIES, APRIL 1971, SELECTED CITIES WITH TAXES ON UTILITY RECEIPTS BUT NO SALES TAXES

Cities with over 500,000 population:		
Atlanta	Detroit	Memphis
Dallas	Kansas City (Mo.)	Milwaukee
Cities with 250,000 to 500,000 population:		
Dayton	Miami	Norfolk
Honolulu	Minneapolis	Wichita
Cities with 100,000 to 250,000 population:		
Cedar Rapids	Little Rock	Syracuse
Fort Lauderdale	Niagara Falls	Utica
Greensboro	St. Petersburg	Waco
Jacksonville	Springfield (Mo.)	
Cities with 50,000 to 100,000 population:		
Arlington (Mass.)	Newport	Pasadena (Tex.)
Davenport	Oak Park	Reno
Dubuque	Odessa	St. Joseph
Fargo	Ogden	Salem
Fort Smith	Ontario	Sioux City
Midland	Oxnard	South Gate (Calif.)
Muncie	Palo Alto	
Cities with 25,000 to 50,000 population:		
Anniston	Greenville	Nutley
Beloit	Kirkwood	Owensboro
Bismarck	Lakeland	Pocatello
Burlington	Marietta	Rocky Mount (N.C.)
Clearwater	Midwest City (Okla.)	Rome
Coral Gables	Minnetonka	St. Cloud
De Kalb	Missoula	Shawnee
Florence	New London	Southfield
Grand Forks	North Miami	West Orange
Grand Island	Norwood	Wilson (N.C.)

Even if they legally can be accomplished, such specialized credit subsidies result in rising interest costs as the favored borrower—with government assistance—forces some other borrower out of the credit markets. Moreover, the typical pattern is for the potential borrowers so forced out to push for special credit legislation on their behalf, which will only result in another round of interest rate increases and governmental intervention. Clearly, the game of musical chairs, particularly when played for such high stakes, is not in the overall public interest.

Reducing the tax burden on saving

The second thing that government can do is to give greater weight to the incentive to save in the composition of the tax structure and of government spending programs. Thus, in raising a given dollar volume of revenues, more of the taxes levied can come out of funds that otherwise would be available for consumption rather than saving.

Representative MOORHEAD. I notice a common theme in all of your testimony on the capital needs problem. The questions I am going to ask are not in those areas where we have agreement, but where we don't agree. One question is in the area of peakload or offpeak pricing.

Mr. Mackie, you testified, as I recall, that the equipment would cost $60 per meter. Professor Weidenbaum replied that if we really got a mass market going, that cost would drop. Are you in agreement with that?

Mr. MACKIE. Oh, yes, completely. That is one of the reasons certainly why the equipment is high priced, because it is produced only in very small amounts. I mentioned that we have 100 such meters on order, and have had for 3 months. The equipment manufacturers just do not produce this equipment in volume. I suppose if someone was here from Westinghouse or General Electric, they would say in answer that they don't have orders for 1 million or 2 or 3 million meters, so they can't start a production line. That would be true. I agree with Mr. Weidenbaum completely that assuming they could really get into production, certainly the costs would drop. They would still cost more because you have a more complicated meter with a more complicated procedure to go through.

Mr. COREY. Could I make a comment?

Representative MOORHEAD. Yes; but that brings me to my next question. Mr. Corey, in your exhibit A, you said that rate structures must be modified to trim peakloads. Without distinguishing whether this should be for all customers or only for the large, you make that statement. Then in your testimony, you do seem to say that we should make greater use of peak and offpeak period pricing for large industrial and commercial users. I would presume, at least in part, that these statements mean that a $60 installation would not mean too much for the large customer since it would still be relatively small compared to the total bill the consumer would have to pay. For the small customer this would be a greater expense. Is that correct?

Mr. COREY. I hate to give long answers, but if I may give a couple answers, that might answer it more fully.

First, of course that is correct. The added cost of between peak and offpeak metering is zero when we are talking about a large steel company, because their meter is on a half-hourly basis. We have computer tape meters now which record at half hour intervals, or whatever intervals you want them to record, so there is no problem at all with doing this sort of thing with a large customer. However, that isn't really the basis of my problem. I certainly do not feel that the inability to get time of day metering is of anything other than of short-run significance. We can certainly get the metering we want if we decide what we want, but my problem has to do much more with elasticity of demand, that is, will Mrs. Murphy do her washing in the middle of the night. It is that sort of thing.

Now, we all know that there will be elasticity of demand. There is always some elasticity, but the question is how much.

And it is one thing to say we know that we can switch certain loads to nighttime. Apparently, the British, in their long study, and I believe it is 2 or 3 years long, they set up special rates and set up special meters and told people, you can have this rate or this rate, and they measured what was going on. They finally decided, as I said in my testimony, that the game wasn't worth the candle. They could not justify the economics resulting from the load switches by the cost of what they were doing.

Now, there has been a lot of criticism of the British study. It has just come out, and it is not surprising that it would be criticized. But the fact of the matter is that they did find this to be the case. And I think it is very important that we not move forward and spend, well, I said for Commonwealth Edison Co., $250 million. We are 3 percent of the industry, and I think it is very important we not go ahead and spend $15 billion or $20 billion of money and then find out that what we have got is something that we would rather not have, and there is something else we should have done. I think we should recognize, first, that there has been a lot of peak and offpeak pricing in the industrial customer area. We have had one or another form of peak/offpeak pricing for the large industrials since before I started work for the company. Over the last 15 or 20 years, we have had nighttime discounts, which have not been widely used, but which have been available to all large customers. To aluminum companies or to anyone who would come to the Chicago area, we have held out an interruptible rate of very low rates for 20 years, and we have never had a single taker. We said that we have to have 10,000 kilowatts to interrupt. If we are going to poke a button and interrupt somebody, the load dispatcher can't be poking 10,000 buttons at once. He has to be able to poke a good sized button, but we were never able to get anybody to take that interruptible rate.

American Electric Power Co. did succeed in getting some nonferrous metal smelters on an interruptible rate in the Ohio Valley and has had them for some time. As I am sure you know, Bonneville and the TVA have had interruptible rates for aluminum smelting for years. But when you then move over into the small areas, we had to abandon the old offpeak water heating rate because of the customer complaint problems. As soon as we got automatic dishwashers and automatic washing machines, you couldn't find room in a house to put in a large enough storage water heater to last through the day. We got so many complaints that we had to get off the rate.

Also, of course, there were timeclock-setting problems. If you have a storm, you have to go out and reset every timeclock. So it should be recognized the French have this offpeak time-of-day metering. I talked to my old friend, Jim Bonbright of Columbia University 15 years ago about this. He would say: Electricite de France, Gordon, has got time-of-day metering.

My reason for bringing this up is because they have 4 million out of their 25 million customers that are on it. They don't have 20 million on it. They have 4 million on it. Now, I don't know the reason for this, but I am absolutely confident that we are going to find a segment of small customers who do have elastic demands and who we can get to switch to nighttime usage. I am also confident that somehow or another we are going to lick the needle-peak problem, but I don't know how. I am baffled to know what we are going to do to get people to get off the single, middle of the afternoon, very, very hot peak. That is a very bad problem. That is very costly to the United States today.

I said in my testimony that the load factor has been dropping. I tried here to compute—and I have forgotten what the U.S. system load factor is—but it has dropped from roughly 65 percent in the late 1960's to under 60 percent today. Ours is at 55 percent, and any big city company in the north which hasn't been able yet to build a large space-heating load, is going to have a tremendous air-conditioning peak. So how do we knock that off? Well, I know how to knock the shoulders off, but I don't know how to knock the peak off. That is too long an answer.

Representative MOORHEAD. Professor Weidenbaum, you say that conserving energy will help to ease the financing problems of the utilities. But can we expect the utility industry to encourage conservation? It has been promotion minded for as many years as I can remember. Can we hope for any action from the industry, Professor?

Mr. WEIDENBAUM. Oh, yes, indeed, because we have seen many, although not all, but many of the utilities change their basic pattern of their advertising to encourage consumers to conserve on power and to offpeak uses whenever possible. I think as a matter of principle, Congressman Moorhead, that people such as the men meeting here today and the industry well understand that the industry has made a transition from declining longrun costs to rising longrun costs. That may sound like technical jargon, but when longrun costs were declining in previous periods, the greater the usage and the faster you expanded your market, the more the average costs would come down. But with rising longrun costs, this means every time you add to your business, Congressman Moorhead, you are adding a market that is more expensive to serve than your existing market, so your average rate goes up.

I found that the senior management by and large in the industry understands this, but when I listen to the middle management get onto television and they are asked this sort of thing, then too often, unfortunately, they blurt out statements such as: "Well, we understand it is the national priority to conserve electricity, but we are in the electric utility business and, you know, the more we sell, the better." And the new message has to penetrate down to them. That is a communication and education problem which can happen in any organization. I don't want to hit the middle management in this industry particularly hard, but that is an internal educational problem.

Representative MOORHEAD. I guess it is that kind of statement that makes me wonder whether they can be selling energy, and still be conserving energy.

Mr. WEIDENBAUM. Part of the problem is competition, Mr. Chairman. When you have the gas company and the electric company in the same area owned separately, competing against each other—well, this is a sore point in the industry, and I almost hesitate to bring it up, but some State commissions have reacted to that by absolutely banning advertising. I think that is unfortunate, and that is the wrong response. Voluntary or otherwise, I think the State commissions or somebody needs to give a kick in the shins or something like that to those companies to stop doing that since national needs have changed.

Representative MOORHEAD. In closing, I would like to say that all industries—the utility industry, the steel industry, and a lot of others—are going to have trouble raising capital. In my opinion, the best way to deal with these capital shortages is through peak-load or off-peak pricing so that you don't have to acquire this terrifically expensive equipment, or at least not as much. There is going to be some opposition, and I certainly take to heart all of your reservations, but I did want to make that point.

I think each one of you has given us some valuable information, and I thank you very much.

Mr. WEIDENBAUM. Mr. Chairman, may I make one observation, and that is obviously I am an enthusiastic advocate of a more sophisticated rate structure, but there is no getting around the fundamental needs of the State commissions to improve the efficiency of their operations and to recognize the basic fact that the cost of producing electricity has gone up and the rates have to be changed.

Representative MOORHEAD. Well, I think the one thing that distinguishes the utility industry from others is the rate lag, which I personally do not have a solution to. It is a State problem, and I think it should be corrected there.

Again, thank you very much.

The committee will stand adjourned.

[Whereupon, at 12:15 p.m., the committee adjourned, subject to the call of the Chair.]

[The following information was subsequently supplied for the record:]

FEDERAL POWER COMMISSION,
OFFICE OF THE CHAIRMAN,
Washington, D.C.

HON. WILLIAM S. MOORHEAD,
Joint Economic Committee,
Congress of the United States,
Washington, D.C.

DEAR CONGRESSMAN MOORHEAD: At one point in the transcript, I indicated I would give further consideration to the desirability of including a refund provision as part of the investment tax credit as proposed in the President's Message to the Congress in October and submit my views for the record. The State of the Union Message of this week has apparently deleted this part of the investment tax credit proposal. It is my opinion that the investment tax credit should be the same for utilities as for industrial corporations, as recommended by the President.

Senator Proxmire and I discussed in some detail the cost impact of the deregulation of new natural gas supplies. This colloquy is set forth in the transcript. I would like to submit, therefore, for the record of the hearing a Commission letter and staff reports sent to Chairman Magnuson on December 13, 1974 in response to his request for an analysis of the impact of Opinion No. 699–H on producers and consumers. Opinion No. 699–H, our order on rehearing in Docket No. 4–389–B, the national rate proceeding, was issued on December 4, 1974 and, as I indicated at the hearing, established a 50¢ base national rate for new gas sold in interstate commerce. The staff analyses submitted to Chairman Magnuson are relevant to Senator Proxmire's inquiry.

In addition, I am supplying a Bureau of Natural Gas Staff Report, "A Realistic View of U.S. Natural Gas Supply," issued on January 2, 1975, which is the latest in a series of staff reports concerning the national gas supply situation and the prospects for future supplies.

Sincerely,

JOHN N. NASSIKAS, Chairman.

Enclosures.

FEDERAL POWER COMMISSION,
OFFICE OF THE CHAIRMAN,
Washington, D.C., December 13, 1974.

HON. WARREN G. MAGNUSON,
Chairman,
Committee on Commerce,
U.S. Senate,
Washington, D.C.

DEAR CHAIRMAN MAGNUSON: Enclosed herewith are the Bureau of Natural Gas and Office of Economics evaluations of the estimated impact of Opinion 699–H on producers and consumers as requested by your letter of December 6, 1974. As indicated in both staff studies the results are directly dependent upon the assumption which you provided in your letter, that is, "that new supplies at the national rate would constitute a 10 percent increment delivered in the first year with an additional 10 percent increment in the following years through 1980."

The various analyses appear to be adequately explained in the evaluation, but since this is a very complex problem, I will be happy to have our staff furnish your Committee with any further assistance you may require.

It should be observed that Opinion 699–H and related opinions considered all relevant factors bearing on the prescription of a just and reasonable national rate, including the imaact on consumers of higher priced gas supplies and the advantages of a more reliable and adequate supply.

Sincerely,

JOHN N. NASSIKAS, Chairman.

Enclosures.

ANALYSIS OF THE ECONOMIC IMPACT OF FPC OPINION NO. 699–H ON PRODUCERS AS REQUESTED BY SENATOR MAGNUSON IN DECEMBER 6, 1974 LETTER

By letter dated December 6, 1974, Senator Warren G. Magnuson, Chairman of the Senate Committee on Commerce, requested Chairman Nassikas of the Federal Power Commission to:

1. Prepare an estimate of the increase in revenues to producers that result from the 50¢ rate in Opinion No. 699–H (assuming that new supplies at the national rate would constitute a 10 percent increment delivered in the first year with an additional 10 percent increment in the following years through 1980) when compared to both—

(*a*) The 42¢ rate.

(*b*) The rates under the area rates which were superseded by the national rate.

2. Estimate the increase in the value of proven reserves that results from this opinion, when compared to both—

(*a*) Prior area rates.

(*b*) The 42¢ rate.

CONCLUSION AND ASSUMPTIONS

There is some question of interpretation of some language in Senator Magnuson's request. We assume for purposes of this study that Senator Magnuson meant the following:

1. "New supplies" are the total supplies eligible for the new rate under Opinion No. 699–H including (1) production from expired contracts which may be renegotiated, (2) new discoveries and (3) new dedications from the intrastate market.

2. In referring to the Opinion No. 699 rate of 42¢, it has been assumed that Senator Magnuson intended the annual 1¢ escalation provided in the order be applied and therefore this study uses 43¢ which became effective on January 1, 1974.

3. The increase in value of proven reserves that results from this opinion is intended to reflect the increase in value of reserves already committed to interstate commerce, i.e., reserves dedicated to interstate pipelines at the end of 1972.

For purposes of this study we made the following additional assumptions:

1. Gas eligible for the first time for the new gas price in each year until 1980 represents 10 percent of the total production for that year.

2. The gas production from previously on-line supplies in each year declines on the basis of a production decline curve, with the exception of the production from new discoveries which we assume will not decline prior to 1980. In this study we give two sets of examples, one based on the Auten-Davis Decline Curve presented in area rate proceedings and the other utilizing the National Availability Curve developed by our staff.

3. The impact was based on national base rates of 50¢ and 43¢ (the effective new gas rate in 1974 under Opinion No. 699) with amounts added for escalations and production taxes but does not include any adjustments for Btu content or gathering. The previous area rates used are based on an average for the nation weighted by production volumes for the individual areas and also include taxes and escalations provided by Commission orders, and that there would be no increase in previously established area rates; Btu and gathering adjustments were not included.

The impact of the increase in revenues resulting from the 50¢ rate compared with the prior area rates, while provided per your request, does not represent a realistic measure of future increase. Most of the existing area rate ceilings were established several years ago and had the Commission not embarked on a national proceeding resulting in a rate of 50¢, it would have had to revise the existing area ceilings through a series of new area rate cases. Those individual area rates would have averaged nationally to approximately the 50¢ level of the national proceeding since they would have been based on the same cost data as the 50¢ rate.

Based upon these assumptions and utilizing the Auten-Davis Curve we calculate that the quantities of natural gas which would be subject to the new gas rate are those shown in Table 1. Utilization of the National Availability Curve yields the results shown on Table II.

The use of the above assumptions with which we do not agree for reasons developed later in this study results in an impact which is predicated on the additional assumption that there would have been no upward revision of area rates through 1980. On the basis of this portion of the study we conclude that:

1. The current, critical, pervasive shortage of natural gas would be substantially improved or eliminated;

2. The curtailment of gas deliveries by pipelines serving the interstate market would be substantially reduced or ended;

3. Growth in production of natural gas for consumption in the interstate market would resume permitting ultimate sales by the interstate market to grow at an annual rate of 850 billion cubic feet based on the Auten-Davis Curve or 243 billion cubic feet based on the National Availability Curve;

4. Rate increases of interstate pipelines and local distribution companies necessitated by declining system load factors would be ended and rate reductions incident to increased load factors resulting from the growth in annual production would be expected;

5. United States dependence on foreign energy sources would be reduced with favorable impacts on our balance of payments and national defense postures;

6. The availability of increased natural gas supplies at prices significantly below prices of alternate fuels would reduce total energy costs in the United States and tend to reduce or curb the present inflationary spiral;

7. Increased investment in the domestic oil and natural gas producing industries would generate demands for labor, materials, supplies, and productive capital creating an impetus toward economic expansion;

8. The gross cost of these new gas supplies with considering the offsetting benefits set forth above would be $11.9 billion based upon the Auten-Davis Curve and $10.5 billion based upon the National Availability Curve if you compare the new 50¢ rate with the previously existing area rates (ranging from 20.12¢ to 35.19¢) and only $2.8 billion or $2.5 billion, respective if compared with the previously announced new gas rate of 43¢;

9. Existing natural gas inventories which would become subject to the 50¢ rate dedicated to the interstate market and estimated to be 40 trillion cubic feet

appreciate in value by $2.8 billion; when compared to the previous announced rate of 43¢ or by $10.5 billion when compared with previously existing area rates; and

10. The probability of occurrence of these happy circumstances are so remote that one should reject the assumption that annual increments of new gas supplies will approach a 10 percent level. (See Analysis beginning at page 7).

If however, we were to attain a 10 percent annual installment of new gas supplies, the above quantified increased would be more than offset by benefits to gas consumers and national economy.

Having thus concluded that annual new gas increment of 10 percent are unrealistic, we have assessed the cost two more nearly realistic assumptions, i.e., (1) annual gas increments of 5 percent and (2) constant production ween now and 1980 with whatever level of new gas increment necessary to maintain that level of production.

Utilizing each of the above other listed assumptions but substituting a 5 percent annual new gas increment we calculate with use of the Auten-Davis Curve and the National Availability Curve the quantities of natural gas which would be subject to the new gas rate to be those shown on Table III and Table IV, respectively.

On the basis of this portion of the study we conclude that:

1. The current, critical, pervasive shortage of natural gas would deepen;
2. The curtailment of gas deliveries by pipelines serving the interstate market would continue to increase;
3. Rate increases of interstate pipelines and local distribution companies necessitated by declining system load factors would accelerate for the indefinite future;
4. United States dependence on foreign energy sources would be substantially increased with unfavorable impacts on our balance of payments and national defense postures;
5. The decline in the availability of natural gas supplies at prices significantly below prices of alternate fuels would further increase total energy costs in the United States and tend to contribute to the present inflationary spiral;
6. The cost of these new gas supplies without considering the adverse impacts set forth above would be $4.6 billion based upon the Auten-Davis Curve and $4.0 billion based upon the National Availability Curve if you compare the new 50¢ rate with the previously existing area rates (ranging from 20.12¢ to 35.19¢) and only $1.1 billion or $1.0 billion, respectively, if compared with the previously announced new gas rate of 43¢;
7. The probability of occurrence of these circumstances are remote, falling short of reasonable expectations at incentive prices.

Utilizing each of the other above listed assumptions but substituting continued interstate production at 1973 levels we calculate with use of the Auten-Davis Curve and the National Availability Curve the quantities of natural gas which would be subject to the new gas rate to be those shown on Table V and Table VI, respectively. Using the assumption of continued interstate production at the 1973 levels, we conclude that:

1. The current, critical, pervasive shortage of natural gas will remain at present levels;
2. The curtailment of gas deliveries by pipelines serving the interstate market would shortly tend to level off;
3. Rate increases of interstate pipelines and local distribution companies necessitated by declining system load factors would level off;
4. United States dependence on foreign energy sources would increase with unfavorable impacts on our balance of payments and national defense postures;
5. The leveling off of natural gas supplies at prices significantly below prices of alternate fuels would increase total energy costs in the United States and tend to contribute to the present inflationary spiral;
6. The cost of these new gas adverse impacts without considering the offsetting benefits set forth above would be $6.7 billion based upon the Auten-Davis Curve and $10.0 billion based upon the National Availability Curve if you compare the new 50¢ rate with the previously existing area rates (ranging from 20.12¢ to 35.19¢) and only $1.6 billion or $2.1 billion, respectively, if compared with the previously announced new gas rate of 43¢;
7. The level of additional dedications to the interstate market under these circumstances should be reasonable attainable at incentive prices.

Impact on consumers

While this study has endeavored to respond to Senator Magnuson's requests regarding the *impact on the producers*, the answers provided do not reflect the effect upon the consumer. The reason for this is the simple fact that the consumer does not purchase gas from producers. The consumer purchases gas from a retail distribution company which in turn buys gas from the pipelines. The pipelines purchase gas from the producers.

Both the distribution companies and the pipelines have delivery lines installed capable of handling certain capacity. The greater the throughput (load-factor) the lower the unit cost for both transmission and distribution lines. As the load factor decreases the fixed unit costs increase.

Appendix A summarizes this effect on some of the major pipelines. For example, the deliverable volume of Transco is projected to decline from .773 Tcf in 1974 to .411 Tcf in 1978—a 47% decline. Its fixed unit costs in 1974 are estimated at 39.32¢ per Mcf at the 1974 volume but increase to 73.89¢ per Mcf in 1978—an 88% increase. This increase is due solely to a lower load factor. It is not due to a lowering of the capacity in the pipeline, nor is it due to an increase in natural gas producer prices. It is due to a lack of gas to put through the line.

In considering the effects upon consumers, an increase in load factors which reduces transmission and distribution costs must be offset against higher prices to be paid to producers.

ANALYSIS OF ASSUMPTIONS OF 10 PERCENT ANNUAL INCREMENTS OF NEW GAS, 5 PERCENT ANNUAL INCREMENTS OF NEW GAS, AND CONSTANT PRODUCTION AT 1973 LEVELS

It is our judgment that the assumption of a 10 percent annual increment of new gas supplies is unrealistic which does not conform to reasonable probabilities. In order to support the volumes of new gas required to satisfy this assumption the following reserve additions would have to be dedicated to the interstate market between now and 1980:

REQUIRED ANNUAL RESERVE ADDITIONS DEDICATED INTERSTATE

	At 10 percent annual increment	
Year	Under Auten-Davis curve (trillion cubic feet)	Under national availability curve (trillion cubic feet)
1974	12.5	10.9
1975	16.4	14.3
1976	18.4	15.6
1977	17.3	13.4
1978	18.4	14.0
1979	18.7	13.4
1980	19.3	13.5
Total	121.0	95.1
Average	17.3	13.6

The probability of attaining such additional dedications of new gas should be evaluated in light of past experience shown in the following tabulation:

Year	Total reserve additions (lower 48) (trillion cubic feet)	New reserves dedicated interstate (trillion cubic feet)
1966	19.2	9.6
1967	21.1	8.6
1968	12.0	6.3
1969	8.3	6.2
1970	11.1	3.6
1971	9.4	2.2
1972	9.4	5.0
1973	6.5	1.7
Total	97.0	43.2
Average	12.1	5.4

REQUIRED ANNUAL RESERVE ADDITIONS DEDICATED INTERSTATE

Year	At 1973 production level	
	Under Auten-Davis curve (trillion cubic feet)	Under national availability curve (trillion cubic feet)
1974	12.5	10.9
1975	5.5	11.7
1976	6.5	11.6
1977	7.4	11.0
1978	6.8	10.5
1979	6.8	10.2
1980	7.6	9.7
Total	53.1	75.6
Average	7.6	10.8

Thus it is clear that in order to support new gas supply increments at 10 percent per year annual new reserves dedicated to the interstate market must exceed by more than two-fold the average interstate dedications in the prior eight years. Or expressed in other terms new gas reserve dedications to the interstate market through 1980 must exceed the average total national reserve additions since 1966 by 10–40 percent. The above two tabulations make it manifest that the expectation of new gas supply increments aggregating 10 percent annually through 1980 is unrealistic.

By comparison assumptions of either a 5 percent annual increment of new supplies or constant production at the 1973 level are more nearly realistic as indicated in the following tabulation:

REQUIRED ANNUAL RESERVE ADDITIONS DEDICATED INTERSTATE

Year	At 1973 production level	
	Under Auten-Davis curve (trillion cubic feet)	Under national availability curve (trillion cubic feet)
1974	12.5	10.9
1975	5.5	11.7
1976	6.5	11.6
1977	7.4	11.0
1978	6.8	10.5
1979	6.8	10.2
1980	7.6	9.7
Total	53.1	75.6
Average	7.6	10.8

In order to maintain production at the 1973 level it will be necessary to increase the volumes of reserves dedicated to the interstate market by some 40–100 percent over the 5.4 Tcf average of such additions since 1966. However, such dedications of 10.8 Tcf appear reasonably attainable.

Required annual reserve dedications to sustain a 5 percent annual increment of new gas supplies are given in the tabulation below:

REQUIRED ANNUAL RESERVE ADDITIONS DEDICATED INTERSTATE

Year	At 5 percent increment	
	Under Auten-Davis curve (trillion cubic feet)	Under national availability curve (trillion cubic feet)
1974	3.2	1.9
1975	6.0	4.7
1976	6.8	5.2
1977	4.6	2.4
1978	4.4	2.2
1979	3.4	.8
1980	2.5	
Total	30.9	17.2
Average	4.4	2.5

An average dedication of 2.5 Tcf–4.4 Tcf at the new rate would be required to generate a 5 percent annual increment. Past experience indicates that this level of new dedication is below reasonable expectation at incentive prices.

The effects of the various assumptions on the quantities of natural gas subject to the new rates are shown graphically in Figure 1. There are three shaded areas, corresponding to the assumptions of (1) a 10 percent increment delivered annually between 1974 and 1980, (2) continued production at 1973 levels, and (3) a 5 percent new gas increment. In each of the cases, the upper line on the shaded area is determined by using the Auten-Davis formula, and the lower line by the National Availability Curve. Reading from top to bottom on the chart, the 6 lines correspond to the "Totals" columns in Tables I, II, V, VI, III, and IV, respectively.

As indicated by the analysis of the amount of reserve dedications that would be needed to achieve those production levels, it would require between 13.6 and 17.3 Tcf annually to achieve the 10 percent growth rate. It would require between 7.6 and 10.8 Tcf annually to meet the 1973 production level; and 2.5 to 4.4 Tcf annually to meet the 5 percent growth rate. Inasmuch as historical dedications of reserves to the interstate systems average 5.4 Tcf, we conclude that the lowest condition is easily achievable, the middle condition can be achieved if average historical dedication of reserves are repeated, but that the top condition would require dedication of more than twice as much as we have been experiencing since 1966.

Figure 1

NATURAL GAS PRODUCTION

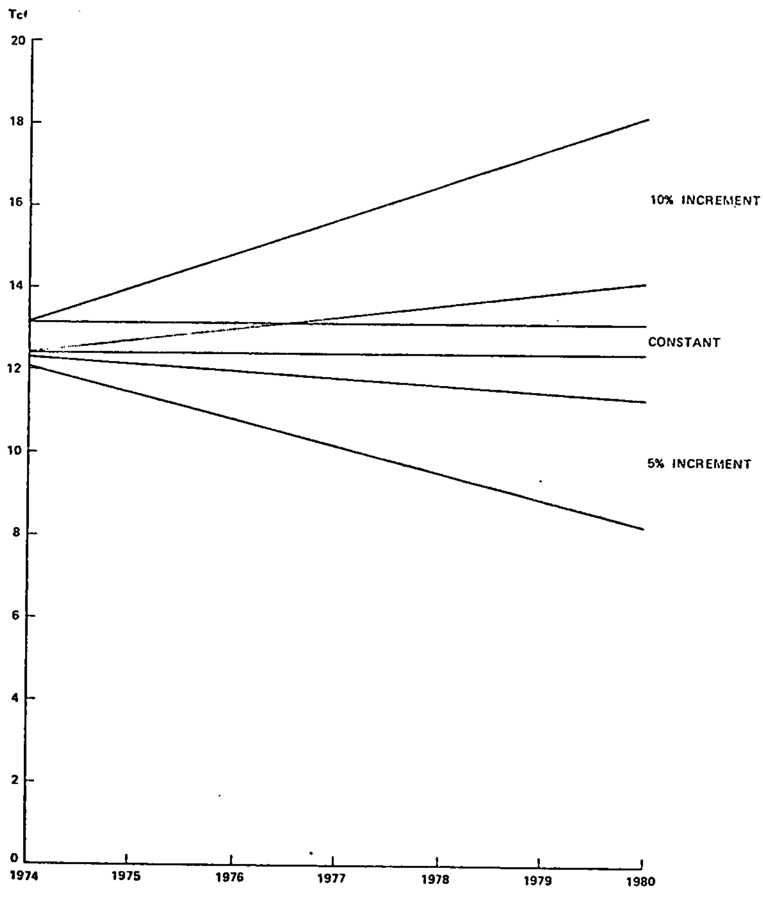


TABLE I.—PRODUCTION (ASSUMES ADDITIONAL ANNUAL INCREMENT OF NEW GAS EQUAL TO 10 PERCENT OF PRODUCTION)

[In trillion cubic feet]

Year (a)	Volumes: Auten-Davis curve — Old gas (b)	New gas (c)	Total (d)
1974	11.993	1.333	13.326
1975	11.458	2.687	14.145
1976	10.921	4.114	15.035
1977	10.170	5.607	15.777
1978	9.493	7.159	16.652
1979	8.775	8.772	17.547
1980	7.982	10.446	18.428
Total (1974–80)	70.792	40.118	110.910

TABLE II.—PRODUCTION (ASSUMES ADDITIONAL ANNUAL INCREMENT OF NEW GAS EQUAL TO 10 PERCENT OF PRODUCTION)

[In trillion cubic feet]

Year (a)	Volumes: National availability curve — Old gas (b)	New gas (c)	Total (d)
1974	11.559	1.284	12.843
1975	10.504	2.534	13.038
1976	9.544	3.794	13.338
1977	8.452	5.061	13.513
1978	7.446	6.327	13.773
1979	6.422	7.592	14.014
1980	5.438	8.861	14.299
Total (1974–80)	59.365	35.453	94.818

TABLE III.—PRODUCTION (ASSUMES ADDITIONAL ANNUAL INCREMENT OF NEW GAS EQUAL TO 5 PERCENT OF PRODUCTION)

[In trillion cubic feet]

Year (a)	Volumes: Auten-Davis curve — Old gas (b)	New gas (c)	Total (d)
1974	11.994	.631	12.625
1975	11.458	1.204	12.662
1976	10.921	1.762	12.683
1977	10.170	2.300	12.470
1978	9.493	2.802	12.295
1979	8.775	3.262	12.037
1980	7.982	3.677	11.659
Total (1974–80)	70.793	15.638	86.431

TABLE IV.—PRODUCTION (ASSUMES ADDITIONAL ANNUAL INCREMENT OF NEW GAS EQUAL TO 5 PERCENT OF PRODUCTION)

[In trillion cubic feet]

Year (a)	Volumes: National Availability curve — Old gas (b)	New gas (c)	Total (d)
1974	11.559	.608	12.167
1975	10.504	1.136	11.640
1976	9.544	1.621	11.165
1977	8.452	2.062	10.514
1978	7.446	2.445	9.891
1979	6.422	2.769	9.191
1980	5.438	3.031	8.469
Total (1974–80)	59.365	13.672	73.037

TABLE V.—PRODUCTION ASSUMED TO REMAIN CONSTANT AT 1973 LEVEL

[In trillion cubic feet]

Year (a)	Volumes: Auten-Davis curve — Old gas (b)	New gas (c)	Total (d)
1974	11.993	1.333	13.326
1975	11.458	1.868	13.326
1976	10.921	2.405	13.326
1977	10.170	3.156	13.326
1978	9.493	3.833	13.326
1979	8.775	4.551	13.326
1980	7.982	5.344	13.326
Total (1974–80)	70.792	22.490	93.282

TABLE VI.—PRODUCTION ASSUMED TO REMAIN CONSTANT AT 1973 LEVEL

[In trillion cubic feet]

Year (a)	Volumes: National Availability curve — Old gas (b)	New gas (c)	Total (d)
1974	11.559	1.767	13.326
1975	10.504	2.822	13.326
1976	9.544	3.782	13.326
1977	8.452	4.874	13.326
1978	7.446	5.880	13.326
1979	6.422	6.904	13.326
1980	5.438	7.888	13.326
Total (1974–80)	59.365	33.917	93.282

APPENDIX A.—REPRESENTATIVE MAJOR PIPELINE COMPANIES—UNIT IMPACT UPON COST RECOVERY OF CHANGES IN SALES VOLUMES

Line	Company	Cost of service [1] (thousands)	Projected sales volumes based upon deliverability [2] (trillion cubic feet)					Unit cost recovery per thousand cubic feet of sales (cents per thousand cubic feet)				
			1974	1975	1976	1977	1978	1974	1975	1976	1977	1978
1	Columbia Gas	$518, 458	1. 390	1. 298	1. 208	1. 200	1. 153	37. 29	39. 96	42. 92	43. 27	44. 99
2	Consolidated	220, 279	. 648	. 641	. 646	. 701	. 660	33. 98	34. 37	34. 08	31. 43	33. 39
3	El Paso (divested)	368, 651	1. 248	1. 088	. 947	. 860	. 775	29. 55	33. 90	38. 93	42. 88	47. 60
4	Florida Gas	66, 455	. 133	. 125	. 116	. 107	. 100	49. 96	53. 28	57. 17	62. 40	66. 13
5	Michigan-Wisconsin	281, 181	. 836	. 837	. 835	. 835	. 773	33. 64	33. 61	33. 68	33. 68	36. 36
6	Natural	371, 967	1. 049	1. 006	. 931	. 843	. 779	35. 45	36. 96	39. 95	44. 11	47. 76
7	Northern	298, 848	. 815	. 747	. 665	. 607	. 553	36. 68	40. 01	44. 95	49. 21	54. 01
8	Panhandle	178, 642	. 649	. 607	. 566	. 524	. 490	27. 54	29. 45	31. 56	34. 08	36. 48
9	Tennessee	440, 800	1. 301	1. 312	1. 211	1. 101	1. 004	33. 88	33. 61	36. 40	40. 02	43. 90
10	Texas Eastern	377, 033	. 834	. 786	. 739	. 717	. 694	45. 21	47. 96	51. 07	52. 58	54. 30
11	Texas Gas	158, 515	. 722	. 686	. 641	. 608	. 552	21. 96	23. 11	24. 72	26. 08	28. 70
12	Transco	304, 015	. 773	. 675	. 577	. 487	. 411	39. 32	45. 07	52. 66	62. 40	73. 89
13	Transwestern	82, 498	. 322	. 278	. 254	. 232	. 211	25. 59	29. 67	32. 51	35. 49	39. 05
14	Trunkline	157, 039	. 419	. 363	. 346	. 309	. 272	37. 50	43. 29	45. 39	50. 80	57. 82
15	United	153, 266	. 967	. 835	. 756	. 662	. 569	15. 85	18. 37	20. 27	23. 16	26. 93

[1] Cost of service data taken from latest rate increase filing and excludes variable costs, primarily purchased gas commodity costs.

[2] Sales volumes reflect deliverability projections adjusted for company use, lost and unaccounted for.

At current production levels, national curtailment is in the range of 15 percent. When production from currently attached reserves drops by 45 percent in only five years, the level of curtailment may well be too great for survival of the gas industry.

Leaving aside questions of what this supply decline will do to these former gas consumers who can no longer be served, at any price, the rate impact of declining deliveries on these consumers who continue to receive service will, in my judgment, be totally unacceptable to this nation. Even if we assume no increase in pipeline fixed costs over the next five years, and even if we assume retention of present pipeline depreciation rates, those customers who receive gas in the future face unprecedented increases in pipeline rates—increases which may be predicted because reduced volumes require a higher rate per unit delivered to recover fixed costs. For a representative group of pipelines, the deliverability decline for each forecasts the following rate impact.

Economic Impact of Opinion No. 699–H

(Prepared by Office of Economics, Federal Power Commission)

This report was prepared in response to the letter of December 6, 1974, from Senator Warren G. Magnuson, Chairman, Senate Commerce Committee, to Chairman Nassikas, requesting certain estimates relating to the economic impact of Opinion No. 699–H.

Senator Magnuson's letter asks for two types of estimates: (1) "an aggregate estimate of the increase in revenues to producers that result from the 50¢ rate, when compared to both the 42¢ rate and the rates under the area rates which were superseded by the national rate" and (2) "an estimate of the increase in the value of proven reserves that results from this Opinion, when compared to both prior area rates and the 42¢ rate." The letter also specifies that the estimates should assume that "new supplies at the national rate would constitute a 10 percent increment delivered in the first year with an additional 10 percent increment in the following years through 1980."

Opinion No. 699–H includes a section, "The Impact on the Consumer" (pp. 54–59), which provides estimates of the impact of the 50¢ base rate on residential bills in selected market areas. The underlying data and methodology for the estimates in that section of the Commission's Opinion provide a basis for answering the first part of Senator Magnuson's request. The first section of this report uses the same approach as in the Commission's Opinion to derive an estimate of the increased revenues to gas producers under the new national rate. This type of calculation, however, yields only a *gross*, and in itself not very meaningful, estimate of the economic impact of Opinion No. 699–H. As stated in the Commission's Opinion," [I]n evaluating the overall public interest, we must consider the benefits to the consumer of an incremental supply of gas to provide reliable gas service compared to the consumer detriment if natural gas supply is reduced." (Page 57.) As a second step, therefore, we have analyzed the benefit side of the cost-benefit equation so that we will have a basis for evaluating the *net* economic impact of the Commission's decision to allow higher prices for new gas. The final section of this report is concerned with the effect of Opinion No. 699–H on the value of proved reserves.

I. Estimated Gross Revenue Impact of Opinion No. 699–H

The calculation of the cost impact on residential consumers in Opinion No. 699–H is based on the following assumptions: (1) constant annual deliveries of 12.1 Tcf, based on FPC Form 11 data for domestic producer sales for calendar year 1973; (2) new supplies, including supplies sold pursuant to renegotiated contracts, equal to either 5 percent or 10 percent of first year deliveries and increasing by additional 5 percent or 10 percent increments in each following year; (3) a constant average wellhead price of 22.62¢ per Mcf, based on FPC Form 11 data for domestic producers for calendar year 1973; (4) new gas prices at the maximum allowed prices in Opinion No. 699–H, with annual escalations of 1¢ per Mcf, a 7 percent production tax, a Btu content of 1,030 per cubic foot, a gathering allowance of 1¢ per Mcf, and an allowance of 1¢ per

Mcf for offshore to onshore delivery; and (5) no allowance for price increases or decreases in future biennial reviews of the national rate.

Using these same assumptions we obtain the following estimates of the total annual impact on producer revenues assuming annual increments of new interstate supplies, including the volumes in renegotiated contracts, of 5 percent (Table 1) and 10 percent (Table 2):

TABLE 1.—ASSUMPTION: 5 PERCENT ANNUAL INCREMENTS OF "NEW" GAS

Year	Deliveries (trillion cubic feet)			Price (cents per thousand cubic feet)			Total revenue (millions)
	Old gas	New gas	Total	Old gas	New gas	Total	
1973	12.1		12.1	22.62		22.62	$2,729
1974	11.5	0.6	12.1	22.62	56.38	24.31	2,930
1975	10.9	1.2	12.1	22.62	57.48	26.11	3,153
1976	10.3	1.8	12.1	22.62	58.59	28.02	3,381
1977	9.7	2.4	12.1	22.62	59.70	30.04	3,625
1978	9.1	3.0	12.1	22.62	60.81	32.17	3,882
1979	8.5	3.6	12.1	22.62	61.92	34.41	4,152
1980	7.9	4.2	12.1	22.62	63.03	36.76	4,435

TABLE 2.—ASSUMPTION: 10 PERCENT ANNUAL INCREMENTS OF "NEW" GAS

Year	Deliveries (trillion cubic feet)			Price (cents per thousand cubic feet)			Total revenue (millions)
	Old gas	New gas	Total	Old gas	New gas	Total	
1973	12.1		12.1	22.62		22.62	$2,729
1974	10.9	1.2	12.1	22.62	56.38	26.00	3,137
1975	9.7	2.4	12.1	22.62	57.48	29.60	3,572
1976	8.5	3.6	12.1	22.62	58.59	33.42	4,032
1977	7.3	4.8	12.1	22.62	59.70	37.46	4,520
1978	6.1	6.0	12.1	22.62	60.81	41.72	5,034
1979	4.9	7.2	12.1	22.62	61.92	46.20	5,574
1980	3.7	8.4	12.1	22.62	63.03	50.90	6,142

The estimated increases in producer revenues attributable to Opinion No. 699–H may be derived from the above tables by calculating the excess over the actual revenues in 1973, on the assumption that the revenues would have been frozen at that level in the absence of the new Opinion.[1] The results are shown below for the 50¢ base price in Opinion No. 699–H and, in addition, for the 43¢ base price (effective January 1, 1974) in the initial Opinion No. 699:

TABLE 3.—ESTIMATED INCREASED REVENUES AS CALCULATED FROM TABLES 1 AND 2

[In millions]

Year	With 5 percent annual increments		With 10 percent annual increments	
	Opinion No. 699	Opinion No. 699–H	Opinion No. 699	Opinion No. 699–H
1974	$162	$204	$324	$408
1975	337	421	675	843
1976	526	652	1,051	1,303
1977	728	896	1,455	1,791
1978	943	1,153	1,885	2,305
1979	1,171	1,423	2,341	2,845
1980	1,412	1,706	2,825	3,413
Total	5,279	6,455	10,556	12,908

[1] Alternatively, the increases may be calculated more directly by multiplying the assumed volumes of new gas in each year by the excess of the new gas price over the old gas price in the same year, and then totalling the results.

We have provided the calculations for both 5 percent and 10 percent annual increments in order to encompass a range of estimates. As is apparent from Table 2, using the assumption of 10 percent annual increments and holding the deliveries at a constant rate implies a very sharp decline in deliveries of old gas and a very rapid increase in deliveries of new gas. The calculations in Table 1 are consistent with a more realistic pattern of old gas deliveries and suggest that annual increments in excess of 5 percent would probably support a rising level of deliveries. Not having a reliable basis for projecting future deliveries of new gas, we have chosen to hold the deliveries at a constant level in both examples.

According to Table 3, the total increase in producer revenues under Opinion No. 699-H, for the 7 years, 1974–1980, is $6.5 billion, assuming 5 percent annual increments, and $12.9 billion, assuming 10 percent annual increments. The comparable estimates for Opinion No. 699 (43¢ base price) are $5.3 billion and $10.6 billion. Accordingly, the increase in the base price between the two Opinions adds $1.2 billion to producer revenues, if we assume 5 percent increments, or $2.4 billion, if we assume 10 percent increments. Part of the increase in producer revenues will be absorbed by higher costs and part will probably accrue as increased profits, depending on the trend of future costs and the industry's success in finding new reserves.

These estimates are subject to the qualifications noted at the beginning of this section, where the various underlying assumptions are listed, and also to two additional limitations. First, the starting price of 22.62¢, which is held constant through 1980, does not allow for permissible future increases in wellhead prices to the applicable old gas price ceilings and the pre-1974 new gas price ceilings.[2] Second, we believe that it is unrealistic to assume that the volume of deliveries to interstate pipelines could be sustained through 1980 at the 1973 level of 12.1 billion Mcf if the new gas ceiling prices were frozen at their 1973 level. According to calculations by the Bureau of Natural Gas, annual deliveries from reserves dedicated to the pipelines at the end of 1973 will decline by about 40 percent by 1980. Simply to offset this decline (i.e., simply to hold deliveries at the 1973 level) will require annual additions of close to 15 billion Mcf to pipeline reserves, compared to annual additions averaging 7.1 billion Mcf from 1964 to 1973. In this connection a key consideration is the comparatively low level of the weighted average of the preexisting new gas ceilings. When expressed in dollars of constant purchasing power, the average was about the same in 1973 as it was in 1960. At that low level, the ceilings did not allow for the increased "real" costs of finding and developing new gas reserves since 1960 or for the needed extra incentive to attract reserves to the interstate market in a gas shortage period.

Our calculations of the revenue impact make no allowance for any effects on the prices of gas sold in the intrastate market. The fact that the prices in Opinion No. 699–H are generally below the prevailing intrastate prices today suggests that the new FPC ceilings are unlikely to create additional upward pressure on intrastate prices. It is true that intrastate producers with contracts that have "favored nation" clauses may benefit, but there is also the possibility that the new Opinion will help to dampen the upward pressure on intrastate prices, because the higher prices should elicit larger supplies of new gas than would otherwise be available to either the intrastate or interstate market.

Finally, we would note that Commissioner Smith's estimate of a $2.6 billion revenue impact attributable to expiring contracts by 1981 (or $2.1 billion by 1980) is already reflected in the estimate of the gross revenue impact in Table 3.[3] For purposes of the calculations, "new gas" is assumed to include the gas in expiring contracts.

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[2] The new gas ceilings averaged about 27¢ prior to Opinion No. 699 H. (This average allows for the new gas price of 35¢ established for the Permian Basin Area on September 28, 1973, for contracts dated after October 1, 1968). Adjusting the starting price of 22.62¢ for the renegotiation of expiring contracts to the pre-1974 new gas price ceilings would lower the estimated increases in producer revenues by about $400 million for the 1974–1980 period.

[3] See Commissioner Don S. Smith's separate statement in Opinion No. 699–H, Appendix A. The estimate assumes that all expiring contracts will be renewed at the pre-1974 new gas price ceilings. Based on past experience, some of the contracts could become eligible for higher prices under the Commission's special relief provisions.

II. ASSESSMENT OF THE NET ECONOMIC IMPACT OF OPINION NO. 699–H

A basic consideration in assessing the net economic impact of Opinion No. 699–H is the marginal cost of attracting new supplies to the interstate market where there has been an imbalance between supply and demand for the past few years. As a general rule, the position of the interstate consumer is improved when he is able to obtain additional gas supplies at a cost that is less than the value of the additional supplies to him. The underlying premise of Opinion No. 699–H is that a price increase is necessary to attract more resources into gas exploration and development and that the cost of these resources will be less than the cost of the resources to produce alternate fuels to satisfy the economy's needs for fuels and energy.

Unfortunately, we do not have enough information to estimate the savings to consumers who will receive the additional gas supply that will be elicited by the new national rate. The available econometric models of gas supply yield widely varying estimates of the price elasticity of gas supply. The most recent study of this subject concludes as follows:

"The three models that have been examined here are probably representative of the current state of the art of econometric modeling of the natural gas industry, but they provide no consensus on how gas supplies are likely to respond to ceiling price increases. It is clear that a knowledge of the dynamic response of exploration and discovery to changes in the price incentive is crucial to the design of regulatory policy; unfortunately, it represents an area that is still not well understood."[4]

The uncertainty about the supply response is limited to the question of how large the response will be. All three models examined in the study are consistent with the view that interstate deliveries will be higher in the years ahead with the Opinion No. 699–H prices than with the preexisting new gas ceilings.[5] Because the higher deliveries will help to offset the curtailments of gas service that would otherwise be necessary, the referred demand to other fuels will be lower as a result of Opinion No. 699–H.[6] This will mean a savings to the economy, since the cost of alternate fuels is substantially higher than the prices in that Opinion.

Let us assume that the Opinion No. 699–H prices will result in a delivered cost of 85¢ per Mcf to gas consumers who would otherwise be curtailed and that the cost of the equivalent energy from the fuels that would be displaced is $1.85.[7] On that basis the savings to the consumers who will receive the incremental supply will equal $1 per Mcf.

Incremental deliveries starting at 0.5 billion Mcf in the first year and increasing by increments of 0.5 billion Mcf in each successive year would provide 14.0 billion Mcf of additional supplies to the interstate market by 1980. At a savings of $1 per Mcf to consumers, the cumulative savings of $14 billion would more than offset the estimated increase in revenues to producers during the 1974–1980 period. (See Table 3 above.) To support annual increments of 0.5 billion Mcf to the interstate market the pipelines would need to obtain an average of 10 billion Mcf of newly dedicated reserves each year. (This calculation is based on the conventional ratio of 20 Mcf of reserves for each Mcf of annual production.) During 1970–1973 the pipelines were able to obtain, on the average, only 3.1 billion Mcf of new reserves each year.[8] It would seem unlikely that the pipelines would be any more successful in obtaining new reserves in the period ahead if the new gas price ceilings remained at the comparatively low level in effect before Opinion No. 699–H was issued. If the new

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[4] R. S. Pindyck, "The Regulatory Implications of Three Alternative Econometric Supply Models of Natural Gas," *The Bell Journal of Economics and Management Science*, Autumn 1974, pp. 633–645. The econometric model developed by the Office of Economics is one of the three models examined in Dr. Pindyck's article.

[5] The increase in gas well drilling activity to all-time record levels in 1973 and 1974 indicates the stimulus provided by higher prices. See *Gas Supply Indicators*, FPC, Second Quarter 1974.

[6] The interstate pipelines project 2.4 billion Mcf of firm curtailments and 0.3 billion of interruptible curtailments for the 12 months ending August 1975. See FPC News Release No. 20849.

[7] The 85¢ price would apply to industrial consumers who are now being curtailed. The price of $1.85 is probably below today's cost of distillate or residual fuel oil.

[8] Based on FPC Form 15 reports. Revisions of estimated reserves acquired in prior years are excluded.

national rate places the pipelines in a position to acquire 10 billion Mcf of new reserves in addition to the amounts they would be able to acquire each year under the old ceiling prices, the estimated savings to consumers would more than offset the estimated increase in producer revenues from 1974 to 1980.[9]

Another offset against the estimated impact of Opinion No. 699–H on producer revenues will be realized through the bonus payments for gas leases in the Federal domain. These payments represent a transfer of anticipated profits from the successful bidders to the U.S. Treasury. Because the new national rate will enhance the potential profits on Federal domain production, the participants in future competitive bidding for gas leases can be expected to raise their bonus bids by most, if not all, of the increase in their expected profits on gas sales from the leases. To that extent, therefore, the higher prices paid by gas consumers will accrue to the benefit of taxpayers in general. Considering that the offshore Federal domain areas accounted for 59 percent of total new long-term sales to the interstate market by large producers in 1972 and 67 percent in 1973, this potential offset—which is of course dependent on the effectiveness of the competitive bidding process—is a major consideration in evaluating the net economic impact of the price increases allowed in Opinion No. 699–H. Moreover, the one-sixth royalty payment to the Treasury provides a partial offset against the increased revenues from new gas sold from leases acquired in past sales or to be acquired in future sales.

III. IMPACT ON VALUE OF PROVED RESERVES

The national rate in Opinion No. 699–H applies to gas from wells drilled after January 1, 1973, gas that is newly committed to the interstate market, and gas that is sold under contracts that are renegotiated after the expiration of the terms of the prior contracts. The value of only a small portion of the existing proved reserves will be affected by the price increases allowed by that Opinion.

Total proved reserves in the lower 48 states are estimated at 214 billion Mcf as of the end of 1973, according to the American Gas Asscoiation.[10] The amount already dedicated to interstate pipelines at the end of 1973 was 134 billion Mcf. Most of these dedicated reserves will be sold at the ceiling prices for flowing gas. The only portion of the interstate reserves that will benefit from the new national rate is the amount that will be sold under renegotiated contracts after the original contracts expire. Almost all of the 80 billion Mcf of proved reserves not dedicated to the interstate market is committed to intrastate contracts and, for reasons given above, is not likely to increase in value as a consequence of the higher price for new interstate gas.

We would calculate the impact of Opinion No. 699–H on the value of proved reserves as follows:

1. According to the data in Appendix A of Commissioner Smith's separate statement in Opinion No. 699–H, the cumulative revenue impact of the new gas rate on sales under contracts whose primary terms will have expired will amount to $2.6 billion by 1981. As of this writing we do not have comparable data for contracts expiring after 1981. If we assume that the annual revenue impact in the succeeding years until 1993, when all of the existing contracts will have expired, will level off at $600 million (compared to about $560 million in 1981), the cumulative revenue impact through 1993 will reach $9.9 billion. The present value of this projected revenue impact is $2.7 billion (assuming a discount rate of 15 percent, which is the allowed rate of return in the Commission's Opinion). For this segment of proved reserves, therefore, we estimate that the effect of Opinion No. 699–H is to increase its value by $2.7 billion.

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[9] The level of successful gas well footage being drilled is currently running at an annual rate of 40 million feet or a little more. Applying the productivity estimate of 485 Mcf (nonassociated gas) per foot drilled, which is the estimate used for the new gas costing in Opinion No. 699–H, we obtain projected annual reserve additions of almost 20 billion Mcf. Adding 3 billion Mcf for associated (oil-well) gas raises the projection to 23 billion Mcf. During 1962–1967 the additions to proved reserves averaged about 20 billion Mcf a year. (The best year for reserve additions was 1956 when 24.7 billion Mcf were reported.) During 1966–1969 the interstate pipelines acquired about 65 percent of each year's additions to proved reserves (excluding revisions), but since then the annual percentage has ranged from 47 percent in 1972 to 17 percent in 1973. (These calculations are based on pipeline reserves reported in FPC Form 15 and proved reserves reported by the American Gas Association.)

[10] Alaskan reserves are excluded because the national rate in Opinion No. 699–H does not apply to gas sales in Alaska. Gas in underground storage is also excluded since such gas is owned by pipelines and distributors.

2. Included in the reported total of proved reserves are some reserves that are uncommitted to sale contracts. The Commission's latest report on the volume of uncommitted gas reserves available for sale in the lower 48 states applies to the status of reserves on June 30, 1973.[11] The uncommitted volume on that date was 3 billion Mcf. Let us assume that an equivalent volume was available when Opinion No. 699–H was issued and that the prospective sales price for these reserves increased from 27¢ per Mcf, the previous average ceiling price for new gas, to the new rate of 56¢ (the 50¢ base rate plus various adjustments included in Table 1). While the price was increased by 29¢, or by about 107 percent, the value of the reserves would increase by a much smaller percent since the higher sales price will be realized only as the reserves are produced. If we assume that the reserves will be produced at a rate of 5 percent for 20 years, the present value of the price increase of 107 percent (discounted at 15 percent per year) would be 33 percent. Thus the value of 3 billion Mcf of reserves worth $810 million at a price of 27¢ per Mcf would increase to $1,077 million. Allowing for the annual escalations of 1¢ per year raises the latter value to $1,175. We therefore estimate the increase in the present value of uncommitted reserves at $365 million.

3. Apart from the reported total of proved reserves there may be some other known reserves that, for one reason or another, are excluded from the reported total. The Commission's Opinion No. 699 refers to a disparity between the FPC staff's estimate of new discoveries in the Southern Louisiana Area and the amount reported by the American Gas Association.[12] Whether this disparity is evidence of underreporting remains a matter of dispute and we are therefore unable to quantify the increased value of unreported reserves, if any.

In summary, our estimate of the impact of Opinion No. 699–H on the present value of reported proved reserves is the sum of $2.7 billion and $365 million, or just a bit over $3 billion.[13] This increased value, however, should not be added to the estimated increase in producer revenues discussed earlier. An increase in the value of proved reserves merely represents the present value of the increased revenues that will be received when the reserves are produced.

[Federal Power Commission, News Release No. 20995, Jan. 2, 1975, Washington, D.C.]

FPC Staff Report Warns of Need for Immediate Measures To Deal With Continuing Gas Shortage

The Federal Power Commission today issued a staff report which states that conventional U.S. gas production has reached its peak and will decline for the indefinite future, and urges immediate and aggressive action to reduce the economic impacts associated with the continuing deficiency.

The report, by the Commission's Bureau of Natural Gas, said it is no longer simply a matter of gas supply failing to meet increasing requirements; "It means that from here on we must make do with less gas in absolute terms." Past efforts to effect a turnaround in the gas supply posture have been largely ineffective, the report stated, and it views the likelihood of success in the future with pessimism.

Curtailment of gas service is starting to pinch the economy and effect citizens in their daily lives; further studies will only underscore what we already know about the gas shortage, the report said. But it emphasized that it is imperative that immediate action be taken to implement programs to cope with declining production and to ameliorate the consequences of increased reliance on supplemental supplies.

These programs must include:

Mandatory gas conservation measures by Federal, State and local jurisdictions for all uses of gas, including residential; and

Allocation of gas by all governmental jurisdictions to high-priority end uses, such as residential, small commercial and essential petrochemical and specialized industrial uses for which no other fuel is available.

The data generally available to forecasters in the National Gas Survey study extended through 1971. We now have two additional years of reserve addition

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[11] FPC Press Release No. 20290, May 9, 1974.

[12] See Opinion No. 699, pp. 47, ff.

[13] At the lower national rate in Opinion No. 699, the estimate would be about $2½ billion.

data available, and while gas well drilling has increased significantly, the report said, additions to lower 48 state reserves continued at low levels. Because conventional production from the lower 48 states will be the keystone of the Nation's gas supply for many years, this study was undertaken to develop an updated perspective of the implications which these recent trends may have for the future.

In a 1969 staff report a clear warning of impending gas shortage was sounded, today's report said. If the earlier report erred it was on the side of understatement; the gas shortage arrived sooner and impacted more severely than anticipated and today shows no sign of abating, the report said. In the five years that have elapsed since that earlier report, no major new government-industry program has been launched which would insure gas service continuing at present levels, much less at levels needed for growth. The gas industry, and particularly the interstate pieplines, are obtaining only a fraction of the new reserve additions needed to maintain present service.

Increased exploration incentives and accelerated leasing of Federal domain lands are the primary policies which should be pursued in developing the lower 48 conventional gas resources, the report said.

The rate at which gas reserve additions can become available is critically dependent on the size of the economically recoverable undiscovered gas resource base. The past prevailing opinion has been that there is a vast amount of undiscovered gas remaining to be developed. However, these large estimates of undiscovered gas have been recently questioned by a distinguished group of scientists, the report points out, who are offering estimates ranging between one-third and one-half of the lowest Geological Survey estimate of 725 trillion cubic feet.

The public policy implications of the dispute are momentous, the report said. If the new low estimates of the resource base are more nearly correct, and events of the past few years lend credibility to these estimates, then programs designed to stimulate exploration are not likely to bring about a significant sustained increase in reserve additions or forestall a decline in production, the report said.

Because the extent of the Nation's undiscovered resource base has a direct bearing on the rate at which future production will decline, the report said, the Federal government should immediately undertake or sponsor an objective, in-depth examination of this matter in order to develop more reliable information.

The report contains an analysis of national supply which indicates that if future net annual additions to reserves are equal to the average experienced since 1968 (9.5 trillion cubic feet per year), then 1985 production capability would only be about 13.8 trillion cubic feet per year. If average annual net additions are equal to 14.7 trillion cubic feet per year, which has been the average experienced since 1960, then 1985 production capability would be 17.4 trillion cubic feet per year.

A similar analysis is made for the interstate sector which shows that a continuation of net annual additions to reserves equal to that experienced during the past six years (3.1 trillion cubic feet per year) would result in a 1985 interstate production capability of 6.8 trillion cubic feet per year. A projection based on average annual net interstate additions to reserves of 7.1 trillion cubic feet per year (the average since 1964) indicates that 1985 productive capability would be 9.6 trillion cubic feet. The report said that policy makers would be well advised to consider the realities of the recent past and develop plans accordingly.

A Realistic View of U.S. Natural Gas Supply

(Bureau of Natural Gas staff report)

PREFACE

This is the latest in a series of reports dealing with the prospects for future national gas supply prepared in the Bureau of Natural Gas. Our 1969 report warned of the impending supply difficulties which had their origin in the late 1960's. A second report issued in February of 1972, dealt more comprehensively with the subject of gas supply in that it addressed the 20 year period extending from 1971 through 1990 and additionally included consideration of the requirements for gas and the prospective availability of gas from supplemental sources. A third exhaustive, in-depth study of conventional supply, demand and projected supplemental supply was conducted as part of the National Gas Survey. While this third report has not yet been published in final form, preliminary drafts have been made available to the public prior to final Commission approval.

The data generally available to forecasters in the National Gas Survey study extended through 1971. We now have two additional years of reserve addition data available and while gas well drilling increased significantly in each of these years, additions to lower 48 state reserves continued at low levels. The downward trend in annual reserve additions which began in 1968 has thus become a trend of six years duration and the impact of this downtrend is being increasingly reflected in the inability of the industry to produce gas at rates sufficient to meet firm requirements. The continuation of these low levels of additions to reserves would appear to indicate that the experience of recent years is not an aberration but an occurrence of historical significance.

Because conventional production from the lower 48 states will be the keystone of the Nation's gas supply for many years to come, this study was undertaken to develop an updated perspective of the implications which these recent trends may have for the future. This report does not generate specific forecasts for the future but rather considers the future production which would become available from a continuation of recent historical trends of additions to reserves.

The National Gas Survey study generated a number of possible levels of production for future years. These ranged from 14.8 Tcf in 1985 under conditions of little or no change from current trends (Case I) to 23.5 Tcf for that same year under the most optimistic assumptions (Case IV). The general assumptions relating to lower 48 state conventional production in Case I were that the then current wellhead prices would be inflated at 4 percent annually through 1975 and then remain level (25–27¢/Mcf) through 1990. No development of the Atlantic offshore area was anticipated and only a low level of development was projected for the Gulf of Mexico and Pacific Offshore regions. In the most optimistic case, it was assumed that wellhead prices would range from 50 cents per Mcf in 1975 to $1.21 per Mcf in 1990, after adjustment for inflation, and that development in all offshore areas would take place according to forecasts provided by the United States Geological Survey. Intermediate cases (Case II and Case III) were developed based on assumptions of price and offshore development lying between these two extremes. The study presented here indicates that if present reserve addition trends continue, future production will fall within the lower range of the four cases developed in the earlier National Gas Survey work.

The data utilized in the preparation of this report is, in general, available in the public files of the Federal Power Commission and in reports of industry trade associations and committees. The interpretations and conclusions drawn from the analysis of these data represent the views and opinions of the Bureau of Natural Gas staff members who prepared this report and do not necessarily reflect the views of the Federal Power Commission or of individual Commissioners.

INTRODUCTION

Chaotic energy developments of the past year, particularly the oil embargo and its attendant problems, have diverted attention from another significant part of the "energy crisis"—rapidly deteriorating supplies of natural gas. This report is an attempt to refocus attention on the realities of the U.S. domestic natural gas shortage and the somber prospects for the future.

The gas supply problem has not yet had an impact on our daily lives in the manner of the gasoline and fuel oil shortages, nor have soaring prices been experienced as with coal, oil products and electricity. Yet, it is just as real and just as ominous as the energy events that dominated the headlines during the past year. Not only is the gas shortage worsening, with little hope of reversal in the near future, but the Nation's capacity to manage a prolonged gas shortage has been seriously impaired by tight supplies and high prices of alternate fuels and by a new dimension of the natural gas shortage—declining annual production. In prior years, even with firm service curtailments, production continued to increase. Now, an unavoidable and rather rapid decrease in annual gas production will intensify an already serious situation in the decade ahead.

In a staff report five years ago the Bureau of Natural Gas warned:

"Evidence is mounting that the supply of natural gas is diminishing to critical levels in relation to demand. . . . On the basis of current trends, only a few years remain before demand will outrun supply."

That report, "A Staff Report on National Gas Supply and Demand (Sept. 1969)", served a clear warning of an impending natural gas shortage. The events of the past five years have fully validated that warning. However, insofar as the report erred, it erred on the side of understatement. The gas shortage arrived sooner and impacted more severely than anticipated and today shows no sign of abating.

In a follow-up report released in February 1972, the Bureau of Natural Gas predicted that gas production would peak in the mid-seventies, and that shortages would be of long duration leading to supply deficiencies of 9 Tcf in 1980 and 17 Tcf in 1990, even after optimistic allowance for new supplies from supplemental sources such as the gasification of coal and gas imports.

In our 1969 report we stated that:

"A major new government-industry program is needed immediately to insure the continued growth of natural gas service during the next decade. The program must be directed to speeding up the exploitation of the natural gas source base and the development of supplemental gas sources."

Today, five valuable years have elapsed and no "major new government-industry program" has been launched which would insure gas service continuing at present levels, much less at levels necessary for continued growth. The natural gas proved reserve inventory continues to decline, curtailments of firm requirements continue to increase, and, as this report will show, the gas industry, and particularly the interstate pipeline companies, are obtaining only a fraction of the new reserve additions necessary to maintain present service.

. For the short term, increasing supply shortages will cause increases in firm service curtailments, widespread plant and business shutdowns and local unemployment and economic problems. In some regions, residential consumers could be affected. For the longer term there are a number of policies which can provide new increments of supply. Increased exploration incentives and accelerated leasing of Federal domain lands are the primary policies which should be pursued in the development of our lower 48 state conventional gas resources. Other policies available include the development of supplemental sources such as gas from coal, synthetic gas from liquid hydrocarbon feedstocks, LNG imports and the development of our Alaskan gas resources. However, even if the above options are immediately adopted as National Energy policy, a decline in available supply probably cannot be forestalled over the time period considered in this report. Federal, State and local policies for coping with this pervasive natural gas shortage must therefore include reallocation of available supply to high priority uses together with nationwide conservation and conversion to alternate fuels wherever feasible.

THE UNDISCOVERED NATURAL GAS RESOURCE BASE

The rate at which natural gas reserve additions can become available in the future is critically dependent on the size of the economically recoverable undiscovered natural gas resource base. The prevailing opinion in the past has been that there is a vast amount of undiscovered natural gas remaining to be developed in the earth below the lower 48 states and the adjacent offshore waters. It has also been taken for granted that this large untapped resource could be rather readily developed by increasing the magnitude of the industry's exploration effort through incentives of one sort or another. This belief in a vast undiscovered natural gas resource base has been premised largely on estimates published over the years by both the United States Geological Survey (USGS) and by the Potential Gas Committee (PGC), an industry sponsored group. The current USGS estimates of the lower 48 states undiscovered natural gas resource base range between 725 and 1,450 trillion cubic feet (Tcf). The PGC undiscovered estimate is 568 Tcf.

These large estimates have been recently questioned by a distinguished group of scientists who are offering estimates ranging between one-third and one-half of the USGS low estimate of 725 Tcf. In this category the most recent estimate of the lower 48 state undiscovered natural gas resource base is 234 Tcf by John

D. Moody, former Mobil Oil Company senior vice president for exploration and production. He is generally supported in his estimate by Richard Jodry, senior scientist with Sun Oil Company, by M. King Hubbert of the USGS and by a Canadian geologist, F. K. North, of Carleton University, who concluded in a study prepared for the FPC's National Gas Survey that the undiscovered natural gas resource base ranges between 400 and 600 Tcf.

In 1962, Hubbert made a remarkably accurate, but controversial, forecast that U.S. oil production would peak and start to decline in either the late 1960's or early 1970's. U.S. oil production actually peaked in 1970 and Hubbert's forecasts are now accorded increasing respect in scientific circles. In 1962, Hubbert forecast that U.S. natural gas production would peak in 1976. In 1973, the growth of total U.S. natural gas production was negligible and preliminary data indicate that 1974 will likely mark the first year of decline.

The differences among the various estimates are so drastic and so crucial in terms of U.S. energy policy making that a committee of the National Academy of Sciences is now attempting to mediate the dispute. The public policy implications of the dispute are momentous. If the new low estimates of the resource base are more nearly correct, then programs designed to stimulate exploration are not likely to bring about a significant sustained increase in reserve additions or forestall a decline in production for future years. Such programs could, however, retard the rate of production decline which in itself would be of great importance.

Events of the past few years have tended to lend credibility to the lower range of estimates. There has been a significant increase in the level of exploratory drilling for gas over the past several years, yet discoveries and reserve additions continue to decline. Presumably, the oil companies are drilling their best prospects but are finding fewer gas deposits of significant size.

When considering the undiscovered natural gas resource, whatever its magnitude may be, one must be careful of the concept involved. Some energy commentators have used the word "supply", or "number of years supply" in connection with undiscovered resource estimates. This is erroneous and misleading. It is meaningless to equate undiscovered resources to future levels of production necessary to meet requirements, without consideration of the constraints on industry capabilities and performance and the nature and occurrence of the resource base including characteristics of gas deliverability. The future transfer of presently undiscovered resources to the supply inventory takes place only through the mechanism of discovery and subsequent development.

It is well known that for any finite, depletable natural mineral resource the large, high-grade, easy-to-find deposits are discovered during the early years of the depletion cycle and that the later years of the cycle are marked by the discovery of smaller, scattered deposits and the development of technology to exploit large, lower grade deposits. While large, low-grade deposits of natural gas are known to exist, particularly in formations with low permeability, acceptable production techniques do not appear to be presently available to commercially develop and produce this gas.

The recent decline in the natural gas finding rate may be the most significant statistic in assessing prospects for the future. This decline may be seen in the trend of net non-associated reserves added per succesful gas well foot drilled shown below.

NET NONASSOCIATED RESERVES DEVELOPED PER SUCCESSFUL FOOT DRILLED, LOWER 48 STATES

Year	Net reserve additions (billion cubic feet)	Successful gas well footage (thousands of feet)	Finding rate (thousand cubic feet per foot)
1966	16,136	24,390	662
1967	17,283	20,789	831
1968	12,335	20,119	613
1969	6,875	24,064	286
1970	9,351	22,852	409
1971	8,565	22,609	379
1972	7,597	26,743	284
1973	3,717	35,587	104

These data reflect the impact of the downward revisions to non-associated reserves which have been experienced each year since 1969. The downward trend can still be seen, however, if the finding rate is developed on the basis of total yearly additions to reserves exclusive of revisions. Finding rate data developed in this manner are shown in the tabulation on the following page.

NONASSOCIATED RESERVES DEVELOPED PER SUCCESSFUL FOOT DRILLED, LOWER 48 STATES

Year	Reserve additions (billion cubic feet)	Successful gas well footage (thousands of feet)	Finding rate (thousand cubic feet per foot)
1966	13,079	24,390	536
1967	13,571	20,789	653
1968	8,298	20,119	412
1969	8,315	24,064	346
1970	9,641	22,852	422
1971	10,037	22,609	444
1972	9,508	26,743	355
1973	9,064	35,587	254

While each of these data series displays a general downward trend over the period considered, it is possible that finding rates could improve in the near future if reported additions are lagging behind reported successful gas well footage or if government policies succeed in eliciting greater supplies than recent historical experience would indicate.

Data developed by the American Association of Petroleum Geologists (AAPG) also show a downward trend. The AAPG classifies new field discoveries by size after examining six years of development history. They have defined as "significant" any gas field containing in excess of 6 billion cubic feet of ultimately recoverable proved reserves. Their data show that the number of "significant" gas field discoveries as a percent of total gas field discoveries is declining, and more importantly the data show that the absolute number of significant gas fields being discovered each year is falling. The number of significant gas field discoveries reached a peak of 99 in 1957 and declined to 41 in 1967, the last year for which six years of development history is available.

"Significant" gas field discoveries by year

Year:	*Number of significant discoveries*
1957	99
1958	73
1959	62
1960	80
1961	46
1962	79
1963	50
1964	53
1965	52
1966	47
1967	41

An analysis of FPC Form 15 data pertaining to interstate sources of supply dedicated between 1964 and 1973 has been made which also illustrates the downward trend in the finding rate. These data indicate that while the trend in the number of new sources dedicated annually has been rather flat, the amount of reserves dedicated has declined markedly because the average source size has declined significantly. These trends can be readily seen in the following table and in Figures 1 and 2.

NEW INTERSTATE SOURCES DEDICATED

Year	Number of new sources	Reserves dedicated (billion cubic feet)	Average new source size (billion cubic feet)
1964	193	4,634	24
1965	158	9,485	60
1966	252	9,564	38
1967	207	8,614	12
1968	155	6,288	41
1969	188	6,216	33
1970	148	3,659	25
1971	164	2,225	14
1972	257	5,040	20
1973	184	1,713	9
Total	1,906	57,436	30

FIGURE 1
INTERSTATE RESERVE DEDICATIONS
FROM NEW SOURCES BY YEAR

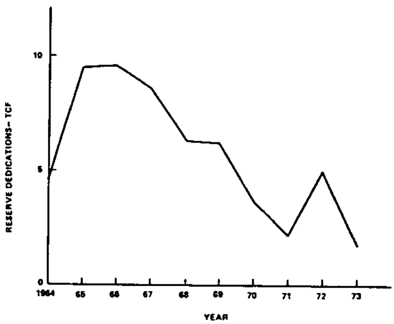


FIGURE 2
AVERAGE SIZE OF NEWLY
DEDICATED INTERSTATE SOURCES

The data cited above do not provide us with information on which we can draw definitive conclusions concerning the size of the undiscovered resource base, one way or the other. Furthermore, the information available does not allow us to determine with certainty if these indicators are related primarily to the size of the resource base or are manifestations of the system under which its development is taking place. These statistics do, however, lend support to the possibility that the undiscovered resource base may actually be much smaller than was previously suspected. Our purpose in raising this issue is not to indicate our support for either camp; it is to focus attention on some very serious questions which have been raised concerning the magnitude of the undiscovered natural gas resource base. Formidable problems lie ahead as the Nation attempts to develop these resources no matter which of the various resource estimates ultimately proves to be most nearly correct. Energy policy makers would be well advised, however, to develop plans and policies keyed to the possibility that the Nation may indeed be experiencing the early effects of a resource being pushed toward exhaustion.

In the sections which follow we will examine some of the production possibilities which result from several assumed levels of future reserve additions. In the light of the resource questions being raised by Moody, Hubbert, Jodry, North and others, we think that those possibilities based on a continuation of recent reserve addition trends take on new meaning.

NATIONAL SUPPLY ANALYSIS

Total U.S. natural gas production increased at an average annual rate of about 7 percent for more than 25 years to 1970. For the three years since 1970 the growth curve has flattened out and preliminary data for 1974 projects a 3 percent decline. Curtailments of firm gas service—the cutting edge of the gas shortage in practical terms—started in November 1970 and have risen steadily since then. Curtailments now are substantial in terms of national gas consumption and will increase in the future.

In the discussion which follows we will show the future national gas production that would be available from specific assumed levels of future reserve additions. We will also specify the future reserve additions which would be requried to maintain gas production at present levels as well as the reserve additions which would permit low and moderate production growth rates. This section is concerned with total reserve additions and production in the lower 48 states. A subsequent section of this report treats the interstate segment in a similar manner.

Our projections of production are based on a method called the "National Availability Curve" (NAC) that was introduced in the FPC publication *National Gas Supply and Demand 1971–1990: Staff Report No. 2*, published in February 1972. (The curve was developed from over 900 sources of supply (associated, non-associated and dissolved gas) reported in FPC Form No. 15 and was designed to reflect maximum producing rates of the "average U.S. gas source" at every stage of depletion. The forecast method involves segregating total remaining reserves into "vintages" each of which contains the estimated remaining reserves of those additions reported in a particular vintage year. The maximum productive capability for each individual vintage is based on the National Availability Curve. Then the maximum productive capability of the total reserve inventory is determined by summing the maximum productive capability of all the vintages.

The long term prospects for domestic natural gas production through 1985 appear to be worsening at an unexpectedly accelerating pace. Furthermore, the possibilities of sustained increases in production above the present level appear to be highly unlikely for both the near and long term.

This is shown in Figure 3, where we have utilized the NAC method to plot the theoretical maximum productive capability between 1960 and 1974 and to project productive capability to 1985 under three assumptions of future annual reserve additions: 1. Reserve Additions = 0.0 Tcf, 2. Reserve Additions = 9.5 Tcf, the average since 1968. 3. Reserve Additions R 14.7 Tcf, the average since 1960.

By 1985, projected production under these three assumptions is calculated to be 7.3, 13.8, and 17.4 Tcf, respectively. Thus, even the most optimistic of these projections falls far short of the current level of 22.5 Tcf.

Productive capability derived by the NAC method has been much greater than actual production until the past few years (Figure 4). Productive capability for 1960 was calculated to be 90 percent greater than actual production, but for 1974 it will be only 8 percent greater.

The occurrence of a gap between actual production and computed productive capability is logical for the past, when an abundance of supply was available. It is also understandable now, even though curtailments are being experienced. One reason for the gap at the present time is that some pipeline companies are in reasonably satisfactory supply situations as compared to others and are not required to draw on their reserves at maximum rates all of the time. Also, some reserves are in shut-in status awaiting a pipeline connection, a contract commitment, or for other reasons. Forecasts of production are premised on a diminishing gap between actual production and productive capability until 1985, at which point they are set equal. The 1985 production forecasts, therefore, might be considered slightly high because it is likely that some portion of the reserve inventory, particularly offshore, will be in non-producing status at any particular time.

Figure 4 also depicts our projections of productive capability to 1985 adjusted to reflect the difference between calculated productive capability and actual production experience. The assumption of no future reserve additions is of course unrealistic, but illustration and discussion of this case serves two purposes. First it forecasts the production that is available from the 1973 proved reserve inventory, and second it serves as a base case forecast, a lower limit to the range of possibilities. Under assumption 1, production would plummet beginning now and continuing through 1985 at an average annual rate of decrease of 9 percent annually.

FIGURE 3
NAC PRODUCTIVE CAPABILITY
LOWER 48 STATES TOTAL SUPPLY

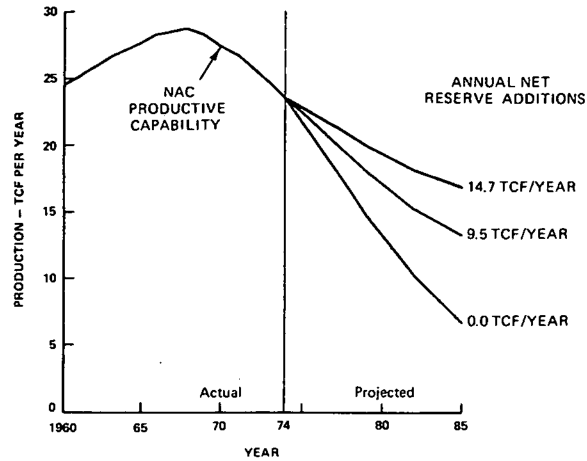
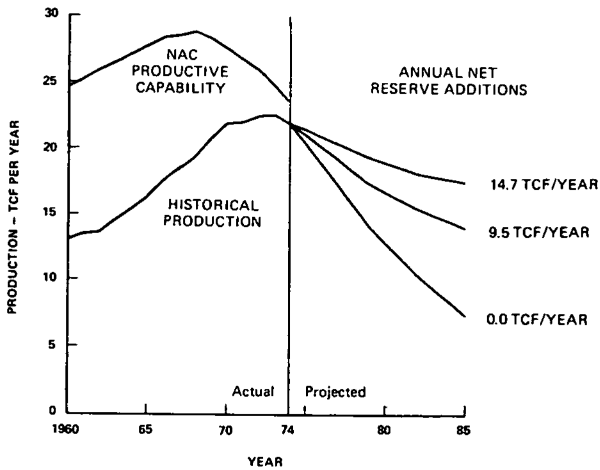


FIGURE 4
PROJECTED PRODUCTIVE CAPABILITY
LOWER 48 STATES TOTAL SUPPLY



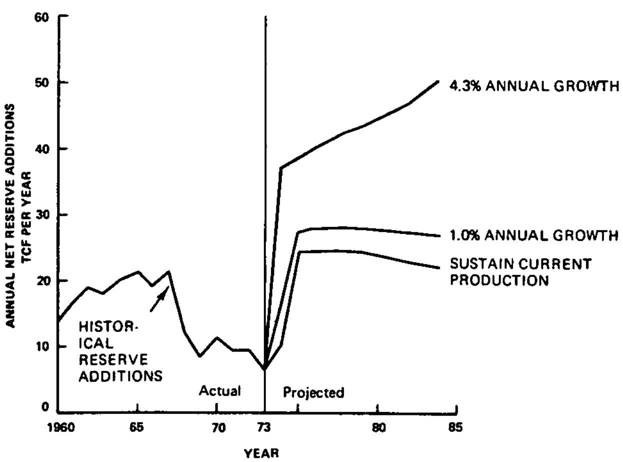
A realistic forecast of gas production requires some accounting for new reserves to be added. Reserve additions during the period 1968–1973 have averaged 9.5 Tcf in the lower 48 states. Our second assumptoin considers what the future reserves inventory could produce based on projected annual reserve additions of 9.5 Tcf, which can be viewed as a continuation-of-present-trends forecast. We feel the chances for this level of additions are reasonably good. We estimate that natural gas production in this instance would fall an average of 4 percent a year to 1985 when production would be 13.8 Tcf.

Our third projection considers a forecast of annual reserve additions equal to the average since 1960, 14.7 Tcf per year, a rate approximately one and one-half times higher than our projection under a continuation of current trends. In this case domestic gas production would fall an average of 2 percent per year, reaching 17 Tcf in 1985.

Our NAC procedure was also utilized to estimate what schedule of reserve additions would be necessary to keep production at the 1973 level of 22.5 Tcf. As shown in Figure 5 we estimate that in order to hold production at the 1973 level, annual reserve additions must rise to the 22–24 Tcf range by 1975 and then remain at that level. As favorable as the production would be in comparison to the previous projections, it is improbable that new reserve additions will be high enough, in view of the performance of the industry over its entire history to date and particularly in view of its performance over the last six years.

To complete our analysis we illustrate what reserve additions would have to be discovered in order to permit production to continue to grow. Lower 48 states gas production has increased at an average rate of 4.3 percent per year since 1960. Attainment of this rate of increase in annual production would require abnormally high reserve additions which would have to jump immediately to nearly 40 Tcf and continue growing at 1.2 Tcf per year (Figure 5). A more modest production growth rate goal might be 1.0 percent per year which was experienced between 1970 and 1973. In this case, the required annual reserve additions would have to average approximately 27 Tcf each year in the future, also an unlikely eventuality in view of past history.

FIGURE 5
REQUIRED NET RESERVE ADDITIONS
LOWER 48 STATES TOTAL SUPPLY



INTERSTATE SUPPLY ANALYSIS

Interstate production peaked in 1972 at 14.2 Tcf and represented 63 percent of total lower 48 state production. Proved reserves dedicated to interstate pipelines peaked in 1967 at 198.1 Tcf and comprised 69.3 percent of the lower 48 state proved inventory. Since 1969, interstate production and reserves have each been dropping as a percent of total lower 48 state production and reserves as shown on Figure 6. During this same period annual interstate reserve additions as a percent of national reserve additions declined as shown on Figure 7.

Thirty-two states, including most of the large heavily industrialized states, are dependent on interstate gas for at least 90 percent of their total gas supply. Nineteen of these states are totally dependent on interstate gas. The pattern of gas consumption in the gas producing states is different from that seen in the states which rely on interstate supplies of gas. For example, residential and

FIGURE 6
INTERSTATE PRODUCTION AND RESERVES AS A PERCENT OF NATIONAL PRODUCTION AND RESERVES

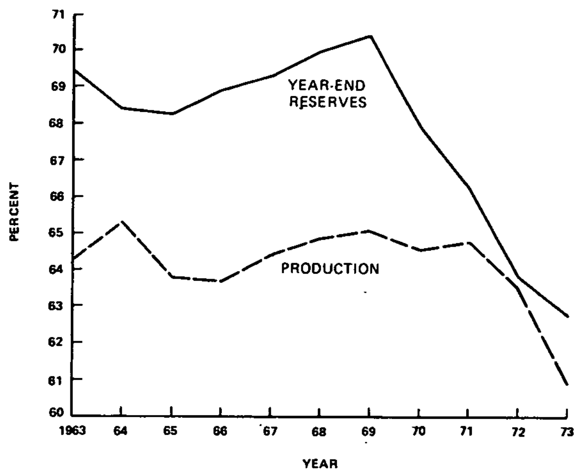
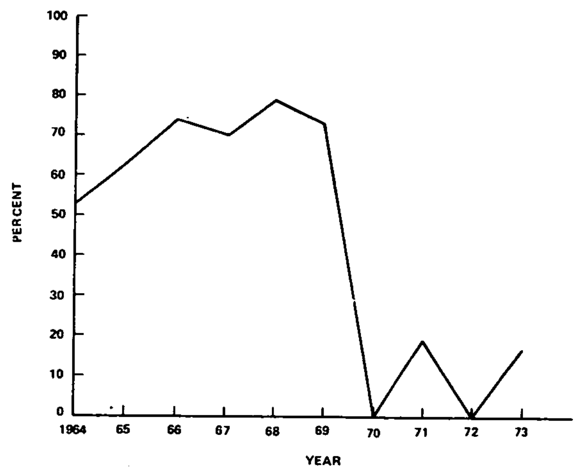


FIGURE 7
INTERSTATE NET RESERVE ADDITIONS AS A PERCENT OF NATIONAL NET RESERVE ADDITIONS



commercial uses of gas account for only 11.7 percent of total gas use in the major producing states but account for 48.0 percent of total gas use in all the other states which are served by the interstate pipeline network.

The gas supply position of the interstate market is weaker than for the nation as a whole. In 1973 annual interstate production was 13.7 Tcf and year-end 1973 interstate proved reserves stood at 134.3 Tcf. This was a drop of 32.2 percent from the interstate reserve peak of 1967 and a 3.7 percent drop in interstate production from the prior year, the first time that production has decreased during the 35 year history of continuous growth enjoyed by the modern interstate pipeline system.

Curtailments of firm service were first experienced in November of 1970 and have steadily risen to 1.1 Tcf in 1973 when they amounted to about five percent of total U.S. production. Preliminary estimates indicate that curtailments will now reach approximately 2 Tcf in 1974 and that for the 1974–1975 heating season they may be as much as 107 percent higher than for the prior year's heating season.

We have applied the National Availability Curve (NAC) to the interstate sector under various reserve addition assumptions in the same fashion as our analysis of national supply. If we assume a continuation of interstate reserve additions at the level experienced over the past six years (3.1 Tcf per year), then interstate production can be expected to drop at an average of 5.6 percent per year between now and 1985. Reserves and production under such a schedule would fall to 55.1 Tcf and 6.8 Tcf, respectively, in 1985. It is abundantly clear that present production simply cannot be sustained at the current level of reserve additions.

A projection based on a longer history of interstate reserve additions does not offer much more encouragement. Reserve additions since 1964 (the earliest date for which we have interstate data) have averaged 7.1 Tcf per year. Even under these conditions we estimate that production would decline about 3.0 percent per year and would amount to about 9.6 Tcf in 1985, a 32 percent drop from the 1972 peak production year. Actually this forecast is fundamentally optimistic because our assumption of annual reserve additions of 7.1 Tcf anticipates the interstate companies receiving about 48 percent of the total national reserve additions. This is most unlikely if recent trends continue. Interstate pipeline companies have acquired only about 8 percent of the national reserve additions over the last four years.

An assumption of zero reserve additions to interstate supply yields a maximum production of only 4.8 Tcf for 1985. The application of NAC to these three interstate cases is shown on Figures 8 and 9.

FIGURE 8
NAC PRODUCTIVE CAPABILITY
INTERSTATE SUPPLY

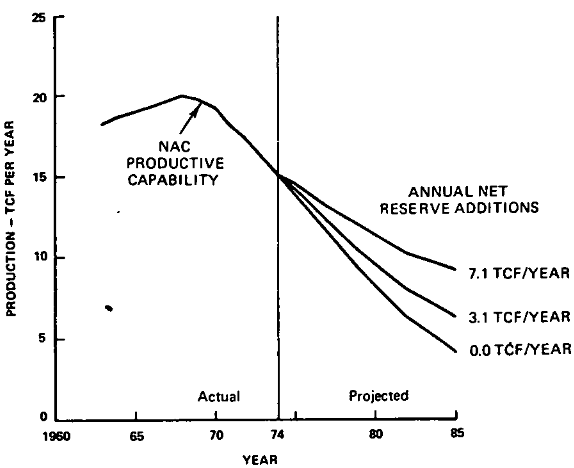
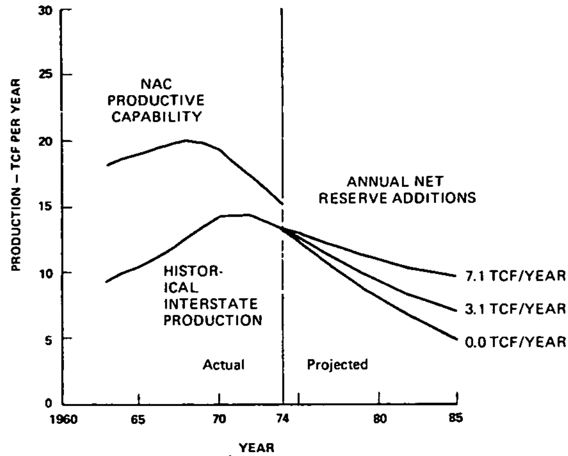


FIGURE 9
PROJECTED PRODUCTIVE CAPABILITY
INTERSTATE SUPPLY



The level of reserve additions necessary to hold production level or provide for growth in annual production of one percent and 4.3 percent are depicted on Figure 10. None of these expectations appear to be realistic. For example, the attainment of a one percent growth in interstate production requires interstate reserve additions to jump within two years to 17.9 Tcf, more than two and one-half times the national reserve additions of 6.5 Tcf in 1973.

INTERSTATE GAS SUPPLY

We have looked at interstate gas supply in some detail. The other segment of total supply is intrastate supply—the gas that is used in the same state in which it is produced and which is equivalent to about one-third of lower 48 state gas use. As we have noted, since 1968 the interstate supply system has been receiving a smaller fractional share of total new gas supply than it did in the years prior to 1968. Conversely, the intrastate sector appears to have been relatively stable in recent years and is now receiving a larger fractional share of total new supply than in the past.

We do not have information on the reserve additions acquired by the intrastate gas companies or on new reserves set aside by producers for their own purposes. In the absence of such data we have assumed that all of the new reserves reported by AGA not committed to the interstate pipelines are being committed to the intrastate gas market. It thus appears that the intrastate gas market is enjoying a relatively favorable gas supply position in spite of the disappointing record for national discoveries and reserve additions. It would seem from the information shown on Table 1 that the intrastate market has had net reserve additions averaging 8.4 Tcf per year for the four years 1970–73 as compared with an average of 5.6 Tcf per year for the prior six year period 1964–69. This is in sharp contrast to the recent reserve addition experience for interstate supply where average annual net reserve additions for the 1970–73 period were only about 0.7 Tcf as compared with approximately 11.4 Tcf for the 1964–69 period. The disparity between the recent net reserve addition records of the two gas industry components is also shown on Figure 11. Table 2 shows trends similar to those seen in Table 1 even though the second table is based on total annual additions to reserves exclusive of revisions. These data would indicate that, to a degree, the recent relative advantage of the intrastate sector has been at the expense of interstate supply.

FIGURE 10
REQUIRED NET RESERVE ADDITIONS
INTERSTATE SUPPLY

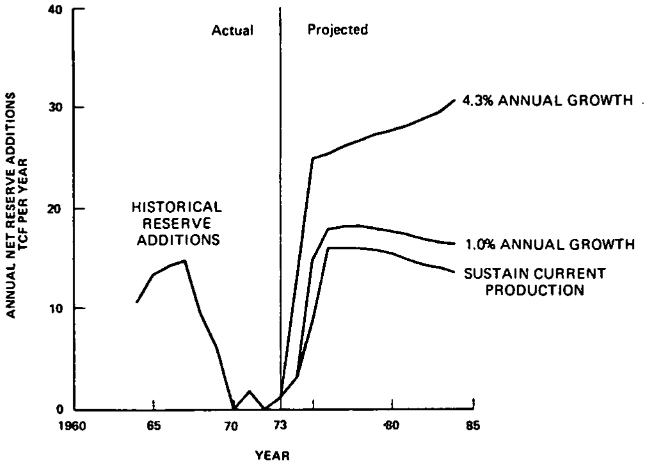


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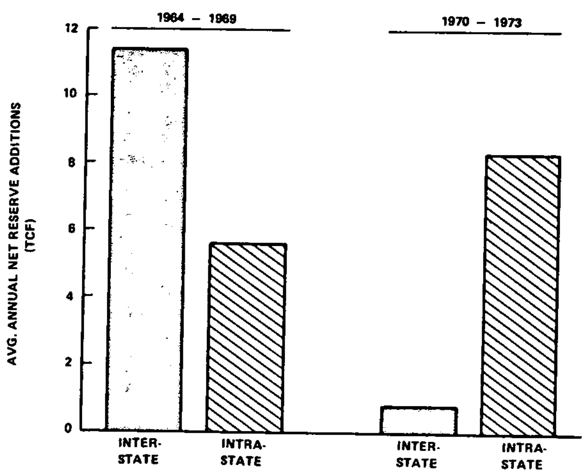
FIGURE 11
AVERAGE ANNUAL NET RESERVE ADDITIONS
INTERSTATE AND INTRASTATE



CONCLUSIONS

A significant point that emerges from our analysis is that conventional U.S. gas production has reached its peak and will be declining for the indefinite future. This reverses a long historical record of growth and introduces a new dimension to the gas shortage. It is no longer simply a matter of gas supply failing to meet increasing requirements. It means that from here on we must make do with less gas in absolute terms. We see this as inevitable regardless of the size of the U.S. undiscovered natural gas resource base. However, the unresolved question concerning the extent of our undiscovered resource base has a direct bearing on the rate at which future production will decline. The Federal government should therefore immediately undertake, or sponsor, an objective, in-depth examination of this matter in order to develop more reliable information in this critical area.

In our review of future gas supply possibilities we have not offered any firm predictions for the future. Policy makers would be well advised, however, to consider the realities of the recent past and to develop plans accordingly. The facts as they relate to the gas shortage and to future supply prospects have been abundantly clear for some time. Past efforts to effect a turnaround in the National supply posture have been largely ineffective and we view the likelihood of success in the future with pessimism. Curtailments of natural gas service are now starting to pinch the economy and affect citizens in their daily lives. Further studies, surveys and analytical exercises will undoubtedly underscore and refine what we already know about the critical aspects of the gas shortage. But we must move immediately and aggressively to implement programs which will reduce the economic impacts associated with continuing gas supply deficiencies.

This effort should, of course, include actions designed to create a new sense of urgency and provide greater impetus to the development of supplemental supply sources and to the development of conventional natural gas resources, particularly in the frontier areas. Nevertheless, even these accelerated efforts will not provide the basis for a continuation of conventional production at present levels. Programs designed to cope with declining production and to ameliorate the consequences of increased reliance on supplemental supplies must therefore include:

Mandatory natural gas conservation measures by Federal, State and local jurisdictions, for all uses of gas, including residential.

Allocation of gas by Federal, State and local jurisdictions to high priority end uses, such as residential, small commercial and essential petrochemical and specialized industrial uses for which no other fuel is available.

The hour is very late. The time for action is *now*.

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TABLE 1.—LOWER 48 STATE NET RESERVE ADDITIONS, INTERSTATE VERSUS INTRASTATE

Year	Total net AGA reserve additions (trillion cubic feet)	Net interstate reserve additions (form 15)		Inferred intrastate reserve additions [1]	
		Trillion cubic feet	Percent	Trillion cubic feet	Percent
1964	20.1	10.6	53	9.5	47
1965	21.2	13.3	63	7.9	37
1966	19.2	14.2	74	5.0	26
1967	21.1	14.8	70	6.3	30
1968	12.0	9.5	79	2.5	21
1969	8.3	6.1	73	2.2	27
1970	11.1	0	0	11.1	100
1971	9.4	2.0	21	7.4	79
1972	9.4	(.2)	0	9.6	100
1973	6.5	1.1	17	5.4	83

[1] Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

TABLE 2.—LOWER 48 STATE TOTAL RESERVE ADDITIONS, INTERSTATE VERSUS INTRASTATE

Year	AGA reserve additions excluding revisions (trillion cubic feet)	Interstate new supply (form 15)		Inferred intrastate new supply [1]	
		Trillion cubic feet	Percent	Trillion cubic feet	Percent
1964	NA	4.9			
1965	NA	10.4			
1966	14.8	10.0	68	4.8	32
1967	14.8	9.9	67	4.9	33
1968	9.8	6.4	65	3.4	35
1969	9.6	6.2	64	3.4	36
1970	11.3	3.5	31	7.8	69
1971	11.1	2.2	20	8.9	80
1972	10.7	5.0	47	5.7	53
1973	10.1	1.7	17	8.4	83

[1] Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

NOTE.—NA=Not available.

Further evidence of the present favorable gas supply situation of the intrastate gas market can be seen in a comparison of recent changes in the proved reserve inventory of the interstate and intrastate components of the gas industry. Whereas the interstate proved reserve inventory has declined 28.8 percent from 1963 to 1973, the intrastate proved reserve inventory has remained at approximately the same level. This can be seen in Table 3.

TABLE 3.—LOWER 48 STATE YEAREND RESERVES, INTERSTATE VERSUS INTRASTATE

Year	Total AGA reserves [1] (trillion cubic feet)	Interstate reserves (form 15)		Inferred intrastate reserves [2]	
		Trillion cubic feet	Percent	Trillion cubic feet	Percent
1963	271.7	188.5	69	83.2	31
1964	276.5	189.2	68	87.3	32
1965	281.4	192.1	68	89.3	32
1966	283.2	195.1	69	88.1	31
1967	285.9	198.1	69	87.8	31
1968	278.6	195.0	70	83.6	30
1969	266.3	187.6	70	78.7	30
1970	255.6	173.6	68	82.0	32
1971	243.1	161.3	66	81.1	34
1972	230.2	146.9	64	83.3	36
1973	214.2	134.3	63	79.9	37

[1] Excludes gas volumes in underground storage.
[2] Derived by assuming that intrastate reserves are equal to the difference between AGA reserves and reserves reported in form 15.