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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-850152
Philadelphia Electric Company	)	

DOCKETED
FEB 24 1986

DIRECT

TESTIMONY AND EXHIBITS

OF

DR. JOHN W. WILSON

DOCUMENT
FOLDER

January 1986

GEC Statement No. 1A

J. W. WILSON & ASSOCIATES, INC.
ECONOMIC COUNSEL
THIRD FLOOR • WATERGATE OFFICE BUILDING
2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

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Testimony of John W. Wilson

I. Qualifications

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 2600 Virginia Avenue, N.W., Washington, D.C. 20037.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my

doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught a wide range of courses in economics at the introductory and intermediate levels. While at West Point, I served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in a wide range of regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients including federal, state and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public

utility regulation, antitrust matters and economic and financial analysis.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with the regulation of public utilities and studies dealing with the economic structure and performance of competitive markets. I have consulted on regulatory matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice, the Commerce Department, the Department of the Interior, the Federal Trade Commission, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada. I have also served on the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment income, and on the NAIC's Advisory Committee on Nuclear Risks.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, and I was the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN REGULATORY PROCEEDINGS?

A. Yes, I have testified as an expert witness before various Federal regulatory bodies and before more than 45 state regulatory authorities. In addition, I have been retained as an expert on regulatory matters by more than 25 regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with utility regulation, financial issues, economic policy and antitrust matters.

I have also testified before the Pennsylvania Public Utilities Commission in the recent past. I testified on behalf of Scott Paper Company in Docket No. L-810060 regarding the proper measure of avoided costs for utilities. I also testified in Docket No. R-842651 on behalf of the Pennsylvania Industrial Coalition

regarding incentive rates for Pennsylvania Power & Light Company's industrial customers.

I also testified in Docket No. I-840381 on behalf of the Staff of the Governor's Energy Council. My testimony in that case addressed the question of developing appropriate performance standards for the Limerick 2 nuclear unit. The program ultimately adopted by the Commission in that proceeding on this matter substantially reflects my recommendations. I have also testified on the subject of utility performance in the states of North Carolina, South Carolina, Arizona, and the Federal Energy Regulatory Commission. More background on my experience is contained in my resume, which is attached as Exhibit__(J.W.-1).

II. Summary

Q. PLEASE IDENTIFY THE SUBJECT MATTER OF YOUR TESTIMONY?

A. I have been asked by the Staff of the Governor's Energy Council (GEC) to assess the merits of adopting operating performance standards for Philadelphia Electric Company's (PECO) nuclear power plants, including Limerick Unit No. 1.

My analysis included an examination of the historic performance of PECO's nuclear units as well as other operating nuclear plants in the United States.

PECO's recent history of nuclear power plant performance has been characterized by an operating record which is below the industry average. The effect of this performance has been to increase the amount of fuel and purchased power costs that have been charged to ratepayers, due to the need to substitute more expensive sources of replacement power when generation from PECO's nuclear facilities was unavailable.

I also reviewed operating performance programs that have been adopted by rate regulators in Pennsylvania

and other states, and I have examined the potential financial impact of assessing performance based cost recovery. As a result of my analysis, I have developed an operating performance standard that I recommend the Commission consider adopting in this proceeding.

III. Theory of Performance Regulation

Q. ACCORDING TO PECO WITNESS HIERONYMOUS, UNDER AMERICAN REGULATION, RATEPAYERS SHOULD BE REQUIRED TO PAY THE COSTS ASSOCIATED WITH PRUDENT INVESTMENTS EVEN IF THOSE INVESTMENTS AND THEIR ASSOCIATED COSTS PROVE TO BE NON-OPTIMAL. HOW DOES THIS COMPORT WITH THE NOTIONS OF INCENTIVE REGULATION?

A. Dr. Hieronymous' position stems from his notion that the obligation to serve on the part of utilities requires that the Company be free of the normal economic sanctions associated with sub-optimal performance. Nothing could be further from the truth. Regulation of public utilities has been instituted to take the place of competitive discipline where it has been determined that adequate levels of market competition are not attainable or in the public interest. Thus, a critical and undeniable regulatory obligation is to disallow the recovery of excessive costs from customers in much the same way as efficient competitors would preclude a market rival from recovering excessive costs.

Thus, contrary to Dr. Hieronymous's apparent beliefs, one of the fundamental principles of utility regulation

is to approximate the cost discipline of competitive markets.

One way to accomplish this objective is through the establishment of operating performance standards. By targeting a cost category that comprises a significant portion of the utility revenue requirement, regulators may be able to more effectively monitor utility performance and encourage the establishment of more effective management practices without assuming control of the day-to-day operation of the utility.

Q. HAVE REGULATORS ALSO RECOGNIZED THE NEED FOR INCENTIVE FACTORS IN REGULATED INDUSTRIES?

A. Yes. For example, the Arkansas Public Service Commission addressed the importance of performance incentives in a fuel adjustment clause mechanism. It stated:

> A fuel adjustment clause has two parameters -- the base price and the base generation mix. A single base clause does not differentiate among the possible generation mixes. The Commission believes the generation mix is important and that the fuel adjustment clause must explicitly address itself to the mix.
>
> The firm must have an incentive to generate electricity at minumum cost to the ratepayers. Minimum cost results when not only

fuel costs are minimized but also generation is forthcoming from the most efficient units at all levels of production.

The importance of the generation mix becomes apparent when one observes the effect of a single base clause. If a less efficient plant is used to produce the same number of Kwh's, then more fuel is needed to generate these Kwh's. The firm is allowed to recoup all the additional fuel expense via the fuel adjustment clause. There has been no incentive to use its most efficient plants. A multiple base fuel adjustment clause, when the generation mix is determined by the optimum redispatch of the system for the test year, provides the necessary incentives for the firm always to employ the most efficient plants.

In addition, states such as California, Arizona, Connecticut, Florida and New Hampshire also have addressed the question of operating performance incentives. I will discuss these programs in a subsequent section.

Q. IS THE SPECIFICATION OF PRECISE PLANT OPERATING STANDARDS FOR PURPOSES OF DETERMINING FUEL AND PURCHASED POWER COST RECOVERY ALLOWANCES ALWAYS THE BEST REGULATORY APPROACH TOWARD IMPROVING OPERATING EFFICIENCY?

A. No. As a general proposition, rules of reason, rather than per se rules, are often more appropriate in dealing with cost recovery issues in electric utility rate

cases. Consequently, the best regulatory plan may be to address actual instances of cost incurrance as they arise and to make specific decisions about the appropriateness of recovering such costs from ratepayers on the basis of the specific facts in each instance. Within this framework, which I believe is fundamental to any commission's traditional regulatory responsibilities, utility company managers and owners should be aware of the fact that the responsibility for cost efficient operations is theirs, and that any excesses which are incurred are subject to disallowance by the regulatory authority.

Utility investors do indeed appear to understand this basic incentive arrangement. The securities price write-offs that have taken place for many utilities with troubled nuclear construction programs reflect investor understanding that recovery of cost excesses from ratepayers will most likely be disallowed. Subsequent regulatory decisions disallowing those costs will, in large part, merely formalize what investors have already done in the market. This is similar to what would occur in a competitive unregulated market where the same type of discipline is imposed by a firm's competitive rivals. There, competitors prevent

firms which incur excessive costs from recovering those cost excesses from consumers.

In short, where regulators accept and carry out the responsibilities accorded to them under traditional regulatory practices, the existing regulatory system can serve as a means of establishing incentives for utility company management. Thus, it may be the case that at the present time any cost inefficiencies associated with the operation of PECO'S nuclear units should simply be disallowed. That is precisely the incentive system of regulation under which the Company built its units and under which PECO has been operating for many years.

Under this type of traditional incentive regulation, utility companies which operate at optimally efficient levels in serving the public interest are rewarded with monopoly service franchises and with return allowances commensurate with the profitability of other successful businesses of comparable risk. Conversely, utilities which do not measure up to optimally efficient performance levels would receive commensurate cost disallowances, thus resulting in lower realized returns,

and, in some instances, the loss of their monopoly franchise.

Whereas a competitive marketplace would be the best incentive of all, the next best option in the case of public utility monopolies is a regulatory authority that is capable of carrying out the essential responsibility of cost disallowance in those specific instances where utilities fail to achieve optimal levels of efficiency.

Q. IS THE GOAL OF STRENGTHENING INCENTIVES FOR IMPROVED PERFORMANCE BY REGULATED UTILITIES NEW?

A. No, performance incentives have always been a concern in designing regulatory strategies. Therefore, while virtually all would agree that incentive regulation can be improved, it is important to avoid undermining incentives that already exist and that have become an integral part of current regulatory practice. In determining whether further performance incentives are needed, one fundamental question is whether they will enable the Commission to better carry out its traditional regulatory responsibilities.

Q. IS IT IMPORTANT TO HAVE EQUALLY BALANCED REWARDS AND PENALTIES IN ORDER FOR A REGULATORY INCENTIVE SYSTEM TO BE EQUITABLE?

A. While that point has been frequently made by utilities, the implied concept of equity is not valid. That is not to say there should be no quid pro quo, but simply that the appropriate quid pro quo is not a structure of equal dollar amounts of rewards and penalties.

This point has been recognized recently in Pennsylvania by the Pennsylvania Electric Utility Efficiency Task Force in its March 1983 report. The Task Force stated:

> Allowing the utility to profit on the basis of factors other than the size of its rate base might encourage the utility to perform as do unregulated firms where cost reduction and efficiency in the use of existing resources often leads to lower costs and increased profits.
>
> If this proves to be the case, utilities may require both the incentive and the resources to improve efficiency, and the cost of providing electrical service may be cheaper than it would be otherwise. Some of the savings would go to the utility and its stockholders in the form of profits, but most of the savings would ultimately flow to consumers in the form of lower costs, higher reliability, and less need for new plants.

Q. WHAT FEATURES SHOULD BE CONSIDERED BY THE DESIGNER OF BENEFICIAL PERFORMANCE PROGRAMS?

The features that are important to the design of beneficial performance programs are as follows:

- Performance programs should be designed so that any rewards and penalties are related to the direct consequences of a utility's actions. These actions would include factors that are under the control of the utility, those that can be influenced by the utility and those that a utility cannot control but affect operations.

- Performance programs should be designed so as to avoid perverse performance motivations. For example, an incentive program which encourages a utility to forego long term efficiency improvements for the sake of obtaining short term performance rewards could prove detrimental.

- Performance programs should be designed so that there is a reasonable probability that a reward or penalty will be incurred as a result of the utility's actions. If the chance of incurring a reward or penalty is only remote, intended incentives are not likely to be strong.

- A performance program should be designed so that it is easy to administer, and so that performance measures are as free as possible from subjective judgment in their application and as invulnerable as possible to accounting or reporting manipulations.

IV. Prior Commission Consideration of PECO Plant Performance

Q. HAS THE ISSUE OF PECO'S NUCLEAR PLANT PERFORMANCE BEEN ADDRESSED PREVIOUSLY BY THIS COMMISSION?

A. Yes. The Company has been involved in four major proceedings before the Commission regarding the performance of its nuclear generating stations.

First, in 1983, the Commission granted a petition by the Pennsylvania Office of Consumer Advocate requesting that an investigation into the February-May 1983 outage of PECO's Salem Unit 1 be commenced, and that PECO be required to show why it should be permitted to recover from its ratepayers the incremental costs of replacing Salem Unit 1 generation with more expensive power as the result of the outage.

The decision to open a formal investigation of the outages and the incremental costs associated with these outages was based on the concerns expressed by the Commission in its October 7, 1983 order:

> The Petition submitted by the OCA presents serious issues of concern to this Commission, which we believe are best developed and

examined by means of a formal, on the record proceeding. These issues concern the circumstances surrounding the various stages of the outage, the amount of any costs occasioned by the outage, the prudence of those costs, and whether any or all of those costs are properly recoverable from PECO's ratepayers. The burden is on PECO to establish that any incremental costs which may have occurred as the result of the outage should be charged to and recovered from ratepayers.

Q. WHAT IS THE NEXT OCCASION ON WHICH THE COMMISSION ADDRESSED THE QUESTION OF PECO NUCLEAR PLANT PERFORMANCE?

A. PECO's administration of its ECR and its ability to operate and maintain its generating units in an economical, efficient, reliable and safe manner were called into question in two additional dockets (M-840375 and M-FACE8408).

Under the ECR in effect at the time, the recovery of actual energy costs incurred by PECO was automatic, absent an investigation similar to the one conducted in the proceedings mentioned above. While the ECR mechanism was initially developed to permit electric utilities to adjust rates to reflect volatile fuel prices without the necessity of conducting lengthy base rate cases, the then-existing ECR mechanism virtually

assured that ratepayers would be charged for all energy costs incurred that were not recovered through the projected energy cost portion of base rates, regardless of whether such costs represented higher fuel expenses, increased sales or diminished generating plant productivity. In short, the then-existing ECR mechanism provided no particular incentive for an electric utility to improve its baseload generating plant performance or more efficiently manage its loads.

The presiding Administrative Law Judge in the consolidated dockets noted that:

> ...the ECR mechanism may be an effective tool to modify a company's behavior.
>
> The ECR mechanism of Section 1307(c) of the Code is available to allow utilities expedited recovery of certain costs. As such it may be considered an appropriate mechanism by which this Commission can provide an incentive to these jurisdictional utilities.

The Commission concurred in the ALJ's conclusions that some fundamental restructuring of the methods used by PECO to recover fuel costs from customers was appropriate.

As a result, the Company was ordered to file a new ECR either in its next general rate case or within sixty days of the Opinion and Order, whichever occurred later. On December 30, 1985, PECO filed its response to that Commission Order. The Commission has incorporated this issue into the instant rate case. My present intent is to file supplemental testimony which will respond in detail to PECO's December 30, 1985 filing.

Q. WHAT IS THE THIRD OCCASION ON WHICH THE COMMISSION HAS CONSIDERED THE PERFORMANCE ISSUE?

A. In December 1984, PECO agreed to guarantee $115.872 million in fuel cost savings for the period February 1, 1985 to March 31, 1986 associated with the commercial operation of Salem 2 in return for allowing full rate base treatment of the facility. Because PECO would therefore only be able to recover fuel costs from ratepayers as if the unit operated at a rate sufficient to produce these levels of savings, this was similar in concept to an operating standard for Salem 2 for the period.

Q. WHAT IS THE FOURTH OCCASION ON WHICH THE COMMISSION HAS CONSIDERED THE PERFORMANCE ISSUE?

A. In Docket No. I-840381 regarding the investigation into the construction of Limerick 2, the Commission adopted a target annual capacity factor of 65 percent for the unit. The Commission established further that operation between 60 and 70 percent would not result in either an incentive or a penalty. Operation outside that range would require the Company to suffer the consequences of poor performance or enjoy the benefits of superior performance.

V. Justification for Performance Standards in This Proceeding

Q. WHY DO YOU BELIEVE THAT THE ISSUE OF PLANT PERFORMANCE IS IMPORTANT IN THIS CASE?

A. First, the Company has incorporated a level of fuel savings that it projects will be forthcoming as a result of the addition of Limerick 1 to its system. However, Company witness Hill has stated that the indicated level of fuel savings in no way reflects any offer to "guarantee" these fuel savings to customers (Tr. 559). Instead, if the anticipated fuel savings do not materialize, the Company would still insist on being able to fully recover all fuel costs incurred from its customers.

Q. DOES PECO'S HISTORIC NUCLEAR POWER PLANT PERFORMANCE REQUIRE THAT THE COMMISSION SERIOUSLY EXAMINE THE NEED TO ADOPT PERFORMANCE STANDARDS FOR ALL OF THE COMPANY'S NUCLEAR UNITS?

A. Yes. At present, PECO is a joint owner in four nuclear facilities, Peach Bottom 2 and 3 and Salem 1 and 2. As

shown on Exhibit___(J.W.-3), Peach Bottom 2 and Salem 1 and 2 have been consistently poor performing units.

Q. HAVE YOU EXAMINED THE OPERATIONAL EFFICIENCY LEVELS THAT HAVE BEEN ACHIEVED BY UTILITIES WITH NUCLEAR UNITS WHOSE REACTORS WERE, AS IN THE CASE OF LIMERICK 1, SUPPLIED BY GENERAL ELECTRIC?

A. Yes, I have. As of 1984, there were twenty-seven operating reactors that have been supplied by General Electric. Page 1 of Exhibit___(J.W.-3) shows the operating performance of these units during the period from 1977 to 1984. Pages 2 and 3 of Exhibit___(J.W.-3) show performance levels for the same period for each of the Westinghouse and Combustion Engineering units. Page 4 shows that during the period 1977-1984, General Electric units performed with average capacity factors of 59.8 percent while those supplied by Westinghouse and Combustion Engineering operated at capacity factors of 61.3 percent, and 68.2 percent respectively.

During the period 1980 to 1984, under additional review and inspection by the Nuclear Regulatory Commission of operating reactors subsequent to the Three Mile Island incident, General Electric units performed at a 56.5

percent average capacity factor with Westinghouse and CE units operating at 60.0 percent and 66.8 percent, respectively. Of course, it should be presumed that the Limerick Plant has been constructed to accomodate post-TMI requirements, and no downtime will be required (as was the case with some previously constructed units) to achieve compliance with these standards.

Nuclear power plant performance is, of course, influenced by how the owner has constructed, operates and maintains the unit, and there is wide divergence in this regard between utilities. Therefore, the Commission should establish standards to insure that PECO's ratepayers are not unfairly impacted by any future failure of PECO to realize efficient operating performance results for Limerick 1 and PECO's other nuclear units.

Q. IS THERE ANY OTHER BASIS FOR YOUR CONCERNS REGARDING PECO'S PLANT PERFORMANCE IN THIS CASE?

A. Yes. PECO's plan for supplying cooling water to the Limerick site underscores this concern. The primary source of water to be used by PECO will be the Schuylkill River. However, PECO is restricted in the amount

of water that can be drawn from the Schuylkill River during periods of low flow and high river water temperature. Thus, the Company requires a supplemental source of water to augment the water from the Schuylkill. Under PECO's plan, this supplemental water would be diverted from the Delaware River to the Perkiomen Creek and then pumped to Limerick via the Point Pleasant Pumping Station.

Construction on the Point Pleasant Pumping Station has been delayed by litigation. While the litigation continues, PECO is pursuing short-term solutions to provide for adequate water.

Q. HOW LONG WILL IT TAKE FOR THE COMPANY TO COMPLETE THE POINT PLEASANT STATION PROVIDED IT RECEIVES THE NECESSARY LEGAL APPROVAL?

A. Company witness Boyer has stated that the project could be completed within one year from the date that construction is resumed on the project (Tr. 989). Therefore, even if construction were to begin by February, 1986, Limerick 1 would be in service for one full year prior to the time when the pumping station could supply the necessary supplemental water. As a result, PECO

must acquire supplemental water sources for the period of time prior to the completion and operation of the pumping station.

Q. IS IT EXPECTED THAT INTERIM WATER SOURCES WILL BE SUFFICIENT TO INSURE THAT LIMERICK 1 CAN ACHIEVE THE COMPANY'S ANTICIPATED CAPACITY FACTOR DURING THIS PERIOD?

A. No. According to Company witness Boyer, either the Company would have to acquire further supplemental sources of water or there would have to be above average rainfall in order to achieve PECO's anticipated 65 percent capacity factor (Tr. 1001-02). Thus, PECO's representation of the fuel savings associated with Limerick 1 operations rests on an assumption that either there will be further supplemental water from as yet unnamed sources or that rainfall will be greater than normal. If neither of these events take place, it would appear that ratepayers would have to bear the cost burden of low production levels from the unit.

Thus, in this case, the Company is requesting the Commission to accept its assumption that there will be sufficient water to enable full operation of the faci-

lity. If, however, the water supply turns out to be insufficient, then the responsibility for the replacement fuel costs would rest not with the Company, but with the Company's customers.

Q. ARE THERE ANY OTHER ISSUES RELATED TO THE WATER AVAILABILITY AT LIMERICK?

A. Yes. From the information contained in Trial Staff Exhibit 11 (included here as Exhibit__(J.W.-2)), the monthly availability of water for Limerick 1 is lowest during the summer period, May through August. Since these months encompass PECO's seasonal peak demand, the Company's customers are going to receive even more limited benefits if Limerick 1 cannot operate at full capacity during the summer period, when replacement power costs are the highest.

According to the chart shown on page 2 of Exhibit__(J.W.-2), the rate of availability of water in the summer implies that Limerick 1 cannot operate above fifty percent availability during this period (Boyer, Tr. 1066). Since the Company represents that the percentage water availability is equivalent to the expected capacity factor, it appears that Limerick 1 will

be less than fully available for a good part of the period when the plant could produce the greatest fuel cost savings. As a result, PECO will be relying on more expensive sources of generation.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE NEED FOR COMMISSION CONSIDERATION OF PERFORMANCE STANDARDS FOR PECO IN THIS CASE?

A. Because PECO has not offered any "guarantee" of the fuel cost savings attributable to Limerick 1, and in view of production risks associated with water availability at the site, the Commission should give consideration to the merits of adopting performance standards that would have the effect of guaranteeing at least some operating benefits associated with PECO'S nuclear plant investment.

Q. HOW WOULD PECO'S RATEPAYERS BE ADVERSELY AFFECTED BY POOR OPERATING RESULTS AT LIMERICK 1 AND OTHER PECO NUCLEAR UNITS?

A. If PECO is permitted to fully recover the costs of all replacement power that is produced or purchased as a result of an inability of the Limerick 1 and other nuclear units to operate at efficient levels, ratepayers would be forced to pay higher costs for electricity.

Q. DO THE MODIFICATIONS TO THE ECR ADOPTED BY THE COMMISSION PROVIDE THE COMPANY WITH A SUFFICIENT INCENTIVE TO IMPROVE THE PERFORMANCE LEVELS OF ITS NUCLEAR PLANTS?

A. While the modifications made to the ECR represent a step in the direction of providing incentives to the Company regarding power plant performance, I believe that further improvements could be made. Without specific operating requirements for nuclear plant operations the Company still has the ability to limit the effectiveness of ECR incentives.

Under the modified ECR, PECO still has substantial control over the development of the forecast level of

energy costs used to establish the fuel component of the base rate. Assumptions regarding power plant performance, unit costs of fuel and sales levels, among other things, are developed by the Company, and cannot be modified except through regulatory proceedings.

Thus, while the Commission's initiatives in this regard do represent a movement towards greater operating efficiency incentives, one concern is that the preponderance of any cost excess as a result of poor operating efficiency levels is still automatically passed through to the Company's ratepayers. While this particular ECR would place a utility at risk for a portion of increased fuel cost levels, its lack of specificity with regard to required performance levels by its nuclear units may still enable the utility to pass through excessive costs by understating appropriate levels for nuclear unit performance.

VI. Overview of Performance Regulation

Q. HAVE OTHER COMMISSIONS ADOPTED POWER PLANT PERFORMANCE REQUIREMENTS?

A. Yes. The Arkansas Public Service Commission has incorporated a target capacity factor for nuclear plants into its fuel adjustment clause. Under the Arkansas standard, Arkansas Power & Light (AP&L) can experience performance levels within a range of 5 points around the target amounts without incurring any penalty or incentives. Substandard performance below the boundaries, however, places this utility at risk for all replacement power costs and superior performance provides AP&L with all of the rewards associated with fuel cost savings.

Potential underrecovery by AP&L is tempered by the fuel clause. If the substandard performance is attributable to an outage lasting longer than 30 days for items other than refueling, AP&L is able to recover 90 percent of any excess fuel costs from the 31st day forward. However, the Arkansas Commission still has the opportunity to conduct a further examination of the reasons for the

outage and determine whether AP&L would be able to recover excess power costs.

The California Commission also has addressed the issue of power plant performance on two fronts. First, it has adopted an incentive/penalty method for Southern California Edison Company's San Onofre 2 unit. Under the California method, if the unit operates at less than 55 percent of its potential output, the utility will be disallowed a recovery on 50 percent of the extra fuel costs arising from the use of more expensive fuels. If the unit operates with a capacity factor above 80 percent, the utility can keep 50 percent of the extra fuel cost savings.

The motivation for this particular standard was expressed in the order in which the program was adopted. It held that:

> it is important to consider the allocation of performance risks and incentives for superior performance at the beginning of the SONGS 2 plant life.

This action, however, was not the first action taken by this Commission regarding power plant performance. In 1981, it adopted an incentive procedure for Southern

California Edison's coal units. Under that program, target capacity factors and heat rates were established. Performance outside of a statistical range for both of these values (50 percent and 98 percent probability intervals around the standard) carries with it both penalties and rewards. The adoption of the standards by this Commission was justified because they thought:

> A procedure such as suggested by Staff in this proceeding provides an opportunity to introduce meaningful incentives into utility operations. As discussed herein, Edison will not only have a restored stake in its coal plant operations, but also an enhanced interest in minimizing fuel oil costs. The benefits of such a procedure far outweight the alleged detriments.

The Arizona Corporation Commission has taken the question of power plant performance standards for Arizona Public Service Company's Palo Verde Unit 1 a step further. Arizona Public Service (APS) is permitted to fully recover its fuel costs provided the unit operates at a capacity factor between 60 and 75 percent. For capacity factors between 50 to 60 and 75 to 85 percent, APS will either be penalized or rewarded by an amount equal to one-half of the additional fuel costs incurred or avoided. In addition, for capacity factors between

35 and 50 percent and those in excess of 85 percent, APS will be rewarded or penalized by an amount equal to the full additional fuel costs incurred or avoided. Finally, if Palo Verde Unit 1 operates at a capacity factor below 35 percent, this will trigger an automatic reconsideration by the Commission of its last rate case decision to determine whether continued rate base treatment of the unit is warranted.

This action was prompted by Commission concerns that its actions with respect to the prospective penalties APS faced regarding any delays in the in-service date of Palo Verde Unit No. 1 or excessive construction costs might prompt an attempt to cut corners on the construction of the plant. Since these actions might result in poor operating performance after commercialization, the Arizona Commission felt:

> Since the economics of any base load unit (but especially a nuclear unit) derive from its relatively low cost of operations, incentives for their proper operation are as equally important as, and indeed compliment, construction incentives.

When the State of Connecticut adopted its fuel adjustment clause for the Northeast Utilities (NU) subsidiaries in 1979, it established a target capacity

factor for the nuclear facilities. The Company develops its base rates on the assumption of a 70 percent capacity factor. The fuel adjustment clause then allows the Company to recover increased fuel costs for nuclear plant performance in the range of 55 percent to 70 percent capacity factor. No additional fuel expense is recoverable from customers if nuclear plant performance falls below 55 percent. The Connecticut Commission believed that establishing the minimum at 55 percent resulted in an:

> equitable sharing of the risks of nuclear outages by the companies and their customers.

The Florida Public Service Commission has established the Generating Performance Incentive Factor (GPIF). The GPIF semi-annually monitors generator availability and heat rates. Weights are assigned to units calculated by their potential contribution to fuel savings or losses. Utilities accumulate GPIF points for actual unit performance. The actual unit availability is compared to the commission-targeted availability on a six month basis. Financial rewards and penalties are issued based on the comparison of actual unit performance with projected targets. Maximum rewards/penal-

ties can increase or decrease the utility's common equity return by up to 25 basis points.

Also, in 1983 the Florida Public Service Commission established a generating performance incentive standard to be applied to the first 12-month period of Florida Power & Light's (FP&L) St. Lucie Unit No. 2 operation. The standard provided for a capacity factor range of 75 percent to 100 percent with a $1 million reward/penalty provision for each 1 percent above or below a target capacity factor of 89 percent. In 1985, FP&L reported to its stockholders that it had achieved a 92.5 percent capacity factor for St. Lucie Unit No. 2 operations, thus qualifying for $3.5 million of incentive rewards.

The New Hampshire Public Service Commission utilizes an Energy Cost Recovery Mechanism (ECRM) that sets target costs for unscheduled outages for each generating unit of Public Service of New Hampshire. Targets are included in basic rates for a prospective 6 month period. At the end of each period an unscheduled outage adjustment is made to rates. The adjustment reflects the difference between estimated and actual increased energy costs resulting from unscheduled outages. The utility keeps or absorbs 10 percent of the difference

between estimated and actual increased costs due for unscheduled outages.

Q. HOW SHOULD PERFORMANCE PROGRAMS ACTUALLY WORK?

A. When a policy for special incentives is established, it should specify the events that will trigger the incentive. This trigger may be simply the passage of time, as with a monthly or semi-annual review of fuel costs; or it may be a specific cost event. When the triggering event occurs, the next step is to calculate the rate change that is allowed. If the commission, at the time it establishes its incentive policy, is able to prescribe a precise method for reflecting the impact in rates, then this step may not involve any substantial controversy. In that event, the commission may wish to permit associated rate adjustments without hearing or investigation.

On the other hand, a commission may wish to limit the scope of incentives to particular cost elements, without prescribing precisely how the impact should be calculated. In that instance, rate adjustments will still require investigation, hearing, and decision by the

commission, though it could still be simpler and faster than a complete rate investigation.

Q. WHAT IS THE BEST WAY TO TRANSLATE SPECIAL INCENTIVES INTO RATE CHANGES?

A. There is very little of a general nature that can be said about the proper way to translate regulatory incentives into rate changes. For fuel-related costs, a uniform charge or credit per kilowatt-hour may be appropriate (with some adjustments for customers taking service at high voltages), but the situation becomes more complex if time-varying rates are adopted. For other cost factors, the best suggestion is to see how the particular cost elements subject to incentive mechanisms are allocated among functions and customer classes in a complete rate investigation, and to use whatever simple translation process most closely approximates that allocation. More complete consideration of this question is properly a matter of rate design; but it is nevertheless important that regulators be aware of it in considering the matter generally.

VII. Recommended Performance Plan

Q. DR. WILSON, HAVE YOU DEVELOPED AN OVERALL PERFORMANCE STANDARD WHICH COULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes, I have. I recommend that the Commission consider adopting the following program. First of all, I recommend the Commission consider adopting a nuclear unit operating requirement standard for all of PECO's nuclear units, including Limerick 1. Under this proposal, PECO could recover all fuel costs incurred so long as its nuclear plants were able to achieve capacity factors in the range of 60 to 70 percent. All replacement power costs attributable to performance below the level of 60 percent capacity factor would not be recovered from customers, while one half of the fuel cost savings achieved by the Company for performance in excess of 70 percent could be kept by the Company.

The second component of this program relates to non-fuel operations and maintenance expenses related to PECO's nuclear facilities. The Commission Staff was ordered by the Commission in the Limerick 2 proceeding to develop a program regarding these expenses for Limerick 2 by June 30, 1986. At the present time, I

propose that the Commission consider adopting this plan for all PECO nuclear units, including Limerick 1.

A final component of a comprehensive cost efficiency program involves post-commercial capital additions. I recommend that the Commission consider requiring the Company to supply information to it regarding additional investment required for each nuclear unit. All such capital expenditures should be reviewed for prudency. Any costs that are not explicitly justified shall be assumed to be imprudently incurred.

Proposed Fuel Cost Standard

Q. WHAT REGULATORY STEPS SHOULD BE TAKEN IN VIEW OF YOUR CONCERN WITH FUEL AND PURCHASED POWER COSTS?

A. In my opinion, the Commission could consider imposing a minimum nuclear unit operating requirement in determining future recoverable fuel costs. This can be accomplished by assuming that the nuclear plants will achieve at least a specified capacity factor for computing the allowable amount of fossil fuel and purchased power cost recovery. Under this approach, to the extent that Limerick 1 and the Company's other

nuclear units achieved suboptimal performance records, it would be the Company's stockholders, rather than ratepayers, who bear the cost of inefficiency. By establishing minimum plant operating standards in determining fuel cost recovery authorizations, the Commission would be dealing with any potential inefficiency problem on a forward looking basis.

Q. HAVE YOU DEVELOPED ANY RECOMMENDATIONS REGARDING AN OPERATING PERFORMANCE STANDARD PERTAINING TO THE LEVEL OF FUEL COSTS TO BE RECOVERED BY PECO?

A. Yes. I propose that the Commission consider adopting the following standards:

(1) Require PECO to estimate its future period fuel costs based on the achievement of a 65 percent average capacity factor for its nuclear units.

(2) Incorporate the unit fuel cost derived by this process into the base rates.

(3) On an annual basis, compare the actual fuel costs incurred with those used to develop the fuel component of base rates. Any underrecovery attributable to nuclear power plant performance below 60 percent is to be absorbed by the Company.

(4) One-half of any overrecovery attributable to nuclear power plant performance above a 70 percent average capacity value is to be received by PECO.

I also recommend that the Commission consider monitoring the planned maintenance schedule for all PECO nuclear units to insure that the standard provides no disincentives to minimize overall system costs.

Q. DO YOU PROPOSE THAT THE COMMISSION CONSIDER PLACING LIMITS ON THE TOTAL AMOUNTS OF REWARDS OR PENALTIES THAT COULD BE EXPERIENCED BY PECO AS A RESULT OF THESE PROPOSALS?

A. No, I do not. The range of 60 to 70 percent will provide the Company with potential operating levels allowing for sufficient discretion over the most efficient means of operating nuclear power plants without fear of unreasonable penalties if good overall operating results are obtained. Overall performance below this level would erode the benefits that customers are entitled to receive in exchange for their commitment to pay for the reasonable fixed costs of nuclear units. Since ultimate control over the operation of the facilities resides with the Company, it is the proper

entity to assume the burden of overall poor performance.

Additionally, the historical average nuclear plant performance in the 60 percent range in the industry since TMI was attributable in large measure to the extremely poor performance of a handful of units as they were taken out of service to comply with new NRC standards. With the bottom end of the range established at 60 percent as an average for all of PECO's units, the Company would have to experience significant outages from more than one of its nuclear units before it would experience nuclear plant performance that would expose the Company to substantial penalties under the standard.

With regard to the distribution of potential benefits forthcoming due to superior nuclear plant performance, it seems reasonable to allow for some rewards. Since PECO's ratepayers have paid for the poor performance of the Peach Bottom and Salem units in the past, a program that splits the benefits of superior performance would provide the Company with significant incentives to improve operating efficiency and thus reduce ratepayer costs. The opportunity to realize some additional

profits under this program may also enable PECO to further improve its own financial position.

Q. HAVE YOU ATTEMPTED TO QUANTIFY THE FINANCIAL IMPACT ON THE COMPANY OF YOUR PROPOSED OPERATING STANDARDS?

A. Yes, I have. Exhibits___(J.W.-4) through (J.W.-6) detail the results of my analysis of the potential financial effects on PECO of these proposed operating standards. Exhibit___(J.W.-4) shows the Company's forecast level of nuclear production for the next four years. Exhibit___(J.W.-5) shows the forecasted level of generation by source during the same period. Exhibit___(J.W.-6) shows the results of an analysis of the likely impact on PECO's fuel costs of variations in the performance of the nuclear plants. Because the financial impacts on PECO of my performance plan are inexorably linked to the schedule and manner of rate recovery, the impacts of my performance proposal on the Company's overall financial position will be presented as part of the financial analysis in my testimony on the question of phase-in.

The data used in this analysis reflects information available from the Company only as of the date of its

December 30, 1985 filing regarding the proposed ECR modifications. In my supplemental testimony I intend to present an estimate of the financial impact on PECO of the proposed operating standards.

Q. PLEASE DESCRIBE THE PROCEDURE FOLLOWED TO DEVELOP YOUR ESTIMATE OF THE FINANCIAL EFFECTS OF YOUR PERFORMANCE STANDARDS?

A. From the information contained in Exhibit___(J.W.-5) and documents supplied by the Company, I was able to develop the information reported in Exhibit___ (J.W.-6). This Exhibit shows the change in fuel cost associated with production from PECO's nuclear plants at various capacity factors. If the Company's nuclear units operate at a 55 percent capacity factor the potential underrecovery of fuel costs would be about $37 million in 1987 to $48 million in 1990. If the Company's nuclear plants perform at an 75 percent factor the increase in pre-tax income to PECO would be $10.9 million in 1987 to about $16.2 million in 1990.

Q. DO THE DOLLAR VALUES OF THE REWARDS AND PENALTIES HAVE TO BE EQUAL IN ORDER FOR YOUR PROPOSAL TO BE EQUITABLE?

A. No, they do not. The mere fact that the Company knows it can profit from superb performance, but at the same time can suffer from sub-par performance, provides a strong incentive to achieve efficient operations. One equity consideration is that the Company would have no uncertainty as to what it would experience as a result of actions directly under its control. From the rate-payers' perspective, equity will be enhanced either by lower costs due to superior performance or protection against excessive charges associated with unacceptable performance levels. Under present arrangements, there are limited incentives for PECO to improve its performance, because it has the capability to recover most fuel costs, regardless of the circumstances under which they are incurred.

Nuclear Non-Fuel Operation and Maintenance Expenses

Q. WHAT PROPOSAL DO YOU RECOMMEND THE COMMISSION CONSIDER REGARDING STANDARDS FOR NUCLEAR NON-FUEL OPERATION AND MAINTENANCE EXPENSES?

A. At present, the Commission Staff is in the process of developing a program with regard to non-fuel operating and maintenance expenses to be applied to Limerick 2.

The program, as conceptualized by the Commission in the Limerick 2 proceeding, would:

> identify expenditures that are out of line with results shown by regression equations and other statistical analyses, and take appropriate regulatory action.

I would propose that the Commission consider applying this plan to all PECO nuclear units, including Limerick 1.

Post-Commercial Capital Additions

Q. DR. WILSON, WOULD YOU PLEASE DESCRIBE YOUR PROPOSAL THE COMMISSION COULD CONSIDER REGARDING POST-COMMERICAL CAPITAL ADDITIONS?

A. Yes. Without any comprehensive review process of post-commercial capital additions, a utility would have limited incentives to insure that any new unit which went into commercial operation was capable of providing service based on the full capability of the plant. Any additional capital expenditures necessary to bring the unit into full production would merely be added without any detailed review as to its prudency, while the Company would be adding the vast majority of the cost of

new facilities to its rates without the plant being sufficient to provide full service.

I would recommend that the Commission consider requiring the Company to supply information to it regarding annual aggregate capital expenditures for its nuclear units in excess of $100 million. With this information, the Commission would be in a position to review the ongoing expenditures prior to the filing of rate cases for prudency. Any costs that are not explicitly justified should be assumed to be imprudently incurred and unrecoverable in future rate proceedings.

VIII. Conclusion

Q. WOULD THE COMMISSION'S ADOPTION OF YOUR PROPOSAL FULFILL THE REGULATORY INCENTIVE OBJECTIVES DISCUSSED PREVIOUSLY?

A. Yes. First of all, the minimum operating standards would reward the Company for positive results of direct actions taken to improve actual performance. Second, by establishing a nuclear performance standard based on the average performance of all nuclear units, rather than requiring each unit to achieve the specified capacity factor, perverse performance motivations could be reduced. PECO would not be forced to implement maintenance shortcuts on individual units in order to achieve a unit target capacity factor. Third, under the program, performance related cost disallowances or rewards are certain to be incurred or received based on actual performance. As shown earlier, the size of these potential rewards or penalties is not insignificant. Thus, the avoidance or achievement of the rewards or penalties will have an impact on the financial position of the Company. Finally, a program that requires base fuel costs to be calculated based on a minimum operating level is easy to administer

because it is tied directly to the observable level of nuclear production.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	
Philadelphia Electric Company	)	Docket No. R-850152

EXHIBITS ACCOMPANYING THE TESTIMONY

OF

DR. JOHN W. WILSON

January 1986

GEC Statement No. 1A

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Docket No. R-850152
Exhibit __(J.W.-1)

JOHN W. WILSON

EDUCATION:

B.S.	(Senior Honors)	- University of Wisconsin
M.S.	(Economics)	- University of Wisconsin
Ph.D.	(Economics)	- Cornell University

EMPLOYMENT

1975 - Present	- President, J.W. Wilson & Associates, Inc.
1973 - 1974	- Independent Economic Consultant
1972 - 1973	- Chief, Division of Economic Studies Federal Power Commission
1971 - 1972	- Economist, Federal Power Commission
1969 - 1971	- Assistant Professor of Economics (and Captain, U.S. Army); United States Military Academy; West Point, New York. Also varsity debate coach, USMA; and antitrust consultant, U.S. Department of Justice.
1966 - 1969	- Teaching Assistant, Cornell University
1965 - 1966	- Research Assistant, University of Wisconsin
1961 - 1965	- Independent Insurance Agent (Licensed in the State of Wisconsin)

PUBLICATIONS:

"Telephone Access Costs and Rates" in Public Utilities Fortnightly, September 15, 1983.

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"Competition in the Petroleum Industry," presented at the Southern Economic Association Conference, Atlanta, Georgia, 1974.

"Electricity Consumption: Supply Requirements, Demand Elasticity and Rate Design," presented at the annual meeting of the American Economic Association, December, 1973; published in the American Journal of Agricultural Economics, May, 1974.

"The Computerized Rate Case: Rate of Return", presented at the Regulatory Information Systems Conference, Missouri Public Service Commission, October, 1973; published in Proceedings.

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The Port of Milwaukee: An Economic Review, University of Wisconsin Press, 1967 (collaborator).

Residential and Industrial Demand for Electricity: An Empirical Analysis, (Ph.D. dissertation, Cornell University, 1969).

EXPERT TESTIMONY:

Before the U.S. House of Representatives -

Committee on Interstate and Foreign Commerce, Subcommittee on Energy and Power; expert testimony concerning the effects of regulation in the natural gas industry, May 1977.

Committee on the Budget, Task Force on Distributive Impacts of Budget and Economic Policies; expert testimony on natural gas matters, 1977.

Committee on the Judiciary, Subcommittee on Monopolies & Commercial Law; expert economic testimony dealing with anticompetitive problems in the U.S. petroleum industry; February 25, 1976.

Committee on Interstate and Foreign Commerce, Subcommittee on Energy and Power; expert testimony pertaining to the deregulation of the field price of natural gas; January 30, 1976.

Committee on Interstate and Foreign Commerce, Subcommittee on Energy and Power, expert testimony concerning natural gas producer regulation; March 1975.

Committee on Interstate and Foreign Commerce, Subcommittee on Telecommunications, Finance and Consumer Protection;

expert testimony pertaining to current structure of the telecommunications industry; June 1980.

Committee on the Judiciary Subcommittee on Monopolies and Commercial Law Oversight Hearings on Mergers and Acquisitions; expert testimony concerning merger policy and antitrust enforcement; December 1981.

Before the United States Senate -

Joint Economic Committee, Subcommittee on Energy; expert testimony concerning antitrust problems related to the development of an integrated fuels industry in the United States; November 1975.

Committee on the Judiciary, Subcommittee on Antitrust and Monopoly; expert testimony dealing with integration between the oil, coal, and nuclear industry; June 1975.

Committee on the Judiciary, Joint Hearing before the Subcommittee on Antitrust and Monopoly and the Subcommittee on Administrative Practice and Procedure; expert testimony dealing with natural gas reserves in the United States, October 1973.

Committee on Commerce; expert testimony on market conditions in the natural gas producing industry and field price regulation, October 1973.

Committee on the Judiciary, Subcommittee on Antitrust and Monopoly, expert testimony dealing with competition in the petroleum industry, June 1973.

Committee on the Judiciary, Subcommittee on Antitrust and Monopoly; expert testimony on matters pertaining to S.403, A Bill to Prohibit Certain Combinations and Control Between Electric and Gas Utilities, May 1971.

Committee on Government Operations; expert testimony pertaining to S.607, A Bill to Establish an Office of Utility Consumers' Counsel, 1970.

Committee on the Judiciary; expert testimony concerning the proposed settlement of the AT&T antitrust lawsuit; March 1982.

Before the California State Legislature -

Expert testimony on matters dealing with natural gas supply in the State of California.

Before the New York State Legislature -

Expert testimony on matters dealing with natural gas supply in the State of New York.

Expert witness in Case No. 27774; Long Island Lighting Company; testimony concerning electric utility rate structure design.

Before the Federal Communications Commission -

Affidavit dealing with the economic structure and performance of competitive markets in connection with implementation of a wide area paging system.

Expert witness concerning AT&T's migration strategy.

Expert witness in CC Docket No. 80-286; testimony on cost methods.

Before the Federal Energy Regulatory Commission (formerly Federal Power Commission) -

Expert witness in Docket ER76-205, Southern California Edison Company; testimony concerning rate of return and other related financial issues.

Expert witness in Docket ER77-175, Florida Power & Light Company; expert testimony concerning transmission service rate and related antitrust issues.

Expert witness in Docket ER76-304, New England Power Company; expert testimony concerning rate of return.

Expert witness in Docket No. ER76-495; Carolina Power & Light Company; testimony concerning rate of return and related financial issues.

Expert witness in Docket No. ER76-45; Consumers Power Company; testimony concerning antitrust and bulk power supply issues.

Expert witness in Docket No. RP76-57-1; Plant City Natural Gas Case; testimony concerning special exemptions for natural gas curtailments.

Expert witness in Docket No. CP74-192, Florida Gas Transmission Company; testimony concerning natural gas supply, and pipeline abandonment and conversion to oil products line.

Expert witness in Docket No. E-9147, Virginia Electric & Power Company; testimony concerning rate of return.

Expert witness in Docket No. E-8884, Carolina Power & Light Company; testimony concerning rate of return, managerial efficiency, and cost of service.

Expert witness in Docket No. E-8570, Southern California Edison Company; testimony concerning rate of return, economic efficiency, cost of service, fuel adjustment clause, and anticompetitive price discrimination.

Expert witness in Docket No. E-8176, Southern California Edison Company; testimony concerning rate of return.

Expert witness in Docket No. RP74-50-5, Florida Hydrocarbons Company and Florida Gas Transmission Company; testimony concerning natural gas curtailment exemptions for liquified petroleum gas production.

Expert witness in Docket No. E-8881, Carolina Power & Light Company; testimony concerning rate of return and related economic matters.

Expert Economic Policy Witness in Docket No. CI73-501, Louisiana Land and Exploration Company; testimony concerning prices and competition.

Expert Rate of Return Witness in Docket No. E-7738, Boston Edison Company.

Expert Economic Policy Witness in Docket No. CI73-293, et al., Belco Petroleum Corporation, et al.; testimony concerning prices and competition.

Expert Economic Policy Witness in Docket No. E-7679, Florida Power Corporation; testimony concerning rate of return, rate structure design and antitrust matters.

Expert Economic Policy Witness in Docket No. CI72-301, et al., Northern Michigan Exploration Company, et al.; testimony concerning prices and competition.

Expert Antitrust Witness in Docket No. E-7618, Southern California Edison Company.

Expert Rate of Return Witness in Docket No. E-7645, Public Service Company of Indiana.

Expert Rate of Return Witness in Docket No. E-7602, Central Telephone & Utility Corporation.

Expert witness for City of Anaheim, California in Docket No. ER76-205; Southern California Edison Company; testimony dealing with rate of return issues.

Expert witness in Docket Nos. ER78-19, ER78-81, Florida Power & Light Company; testimony concerning prices and competition.

Expert witness in Docket No. ER76-714, Indiana & Michigan Electric Company; testimony concerning rate of return.

Expert witness for the Municipal Wholesale Power Group in Docket No. ER77-347, Wisconsin Power & Light Company; testimony concerning price squeeze issues.

Expert witness in Docket Nos. EL78-15 and ER78-339, Public Service of New Hampshire; concerning the inclusion of construction work in progress in rate base.

Expert witness in Docket No. ER78-379, et al., Indiana & Michigan Electric Company; testimony concerning rate of return and capital structure.

Expert witness in Docket No. OR78-1, Trans-Alaska Pipeline; testimony concerning rate of return, rate base, and capital structure.

Expert witness in Docket No. OR79-1, Williams Pipe Line Company; testimony concerning rate base valuation and related regulatory issues.

Expert witness in Docket No. ER78-522, Virginia Electric & Power Company; testimony concerning price squeeze issues.

Expert witness in Docket ER78-360, Connecticut Yankee Atomic Power Company; testimony concerning rate of return and related issues.

Expert witness in Docket No. RP83-11, Transcontinental Gas Pipeline Company; testimony concerning rate of return and sales volumes.

Expert witness in Docket No. ER82-427-000, Southern California Edison Company; testimony concerning fuel procurement practices and nuclear plant operating efficiency.

Expert witness in Docket No. ER82-483-000, Middle South Utilities Company; testimony concerning equalization of costs.

Expert witness in Docket No. ER76-205-003, Southern California Edison Company; testimony concerning price squeeze issues related to wholesale rates.

Expert witness in Docket No. ER83-609, Southwestern Electric Power Company; testimony concerning cost of capital and rate of return.

Before the Nuclear Regulatory Commission -

Affidavit dealing with proposed licensing conditions pertaining to a new nuclear power plant to be constructed by the Florida Power & Light Company, April 1976.

Before the Securities & Exchange Commission -

Expert economic witness for the U.S. Justice Department on the matter of American Electric Power Company, Inc., SEC File No. 70-4596 (proposed merger with Columbus & Southern Ohio Electric Company), February-March, 1971.

Before the United States Department of Energy -

Dealing with gas supplies and natural gas pipeline service to Florida.

Before the U.S. District Court for the -

Northern District of New York, Expert witness in 79-CU-163, Town of Messena, New York v. Niagara-Mohawk Power Corporation; testimony concerning antitrust issues

pertaining to Massena, New York's establishment of a municipal electric distribution system.

Before the U.S. District Court for the -

District of Connecticut, expert witness in antitrust liability and damage phases of Jury Trial in Civil Action B-75-319, Northeastern Telephone Company v. American Telephone & Telegraph Company, et al.

Before the St. Lawrence County Court Commissioners of Appraisal -

Expert testimony, Index 59244, concerning the condemnation value to be established for Niagara Mohawk's distribution property being acquired by the Town of Massena, New York to establish a municipal system.

Before the Alabama Public Service Commission -

Expert witness in Docket No. 17667, Alabama Power Company; testimony concerning rate base and cost of service issues.

Expert witness in Case No. 18548, South Central Bell Telephone Company; testimony concerning the restructuring of WATS rates.

Before the Alaska Pipeline Commission -

Expert witness in Docket P-78-5, Northpole Refinery; testimony on cost allocation and rate design issues.

Before the Arizona Corporation Commission -

Expert witness for Honeywell Information Systems, Inc. in Docket No. U-1345; Arizona Public Service Company; testimony concerning cost of service and marginal cost pricing.

Expert witness in Docket No. 9981-E-1051-83, Mountain States Telephone and Telegraph Company; testimony concerning financial condition, cost of capital and rate of return.

Expert witness in Docket No. U-1345-83-155, Arizona Public Service Company; testimony concerning financial condition, earnings level and cash flow.

Expert witness in Docket No. 9981-E-1051-83-286, Mountain States Telephone and Telegraph Company; testimony dealing with post-divestiture cost estimates.

Before the Arkansas Public Service Commission -

Expert witness in Docket No. U-2748; Southwestern Bell Telephone Company; testimony concerning service and equipment costs, tariff structures and competition in the telecommunications industry.

Expert witness in Docket No. U-2896, Generic Hearing; testimony concerning competition in the telecommunications industry.

Expert witness in Docket No. 82-314-0; Arkansas Power & Light Company; testimony concerning cost of service issues.

Expert witness in Docket No. 83-064-U, Southwestern Electric Power Company; testimony concerning rate of return, CWIP and cash working capital issues.

Before the Canadian Radio Television and Telecommunications Commission -

Expert testimony concerning the competitive implications of Canadian Pacific Telecommunication's application for access to the Bell Canada network.

Expert testimony concerning cost methods in Docket No. 1981-41.

Before the California Public Utilities Commission -

Expert witness in Application No. 55723; Pacific Telephone & Telegraph Company; testimony concerning the basis and economic implications of cost allocation rate levels, and rate design for various types of telephone equipment and service classifications.

Expert witness in Centrex 10191, Investigation into Rates, Tariffs, and Costs of Centrex Service; testimony concerning service and equipment costs, tariff structures, and competition in the telecommunications industry.

Expert witness in Case No. OII 83 06 01, Western Union; testimony concerning "natural" monopolies and regulatory restrictions in telecommunications systems.

Before the Colorado Public Utilities Commission -

Expert witness in Docket No. 1154, 1133, Case No. 5748, Mountain States Telephone & Telegraph Company; testimony

concerning Dimension PBX and Com Key tariffs as well as Western Electric pricing practices and impacts on competitors in the interconnect industry.

Expert witness in Docket No. 1067, Case No. 5703; Mountain States Telephone & Telegraph Company; testimony concerning service and equipment costs, tariff structure and competition in the telecommunications industry.

Expert witness in Docket No. 1425, Public Service Company of Colorado; testimony concerning service extension charges.

Expert witness in Docket No. 34444, Public Service Company of Colorado; testimony concerning service extension charges.

Before the Delaware Public Service Commission -

Expert witness in Docket No. 80-9, Delmarva Power & Light Company; testimony concerning class revenue requirements, review of the Company's proposed rates, and incentives in the design of the fuel adjustment tariff.

Expert witness in Docket No. 81-8, Diamond State Telephone Company; testimony concerning affiliated relationship and terminal equipment.

Expert witness in Docket No. 83-12, Diamond State Telephone Company; testimony concerning Company's financial condition and rate of return.

Before the D.C. Public Service Commission -

Expert witness in Formal Case No. 686, Washington Gas Light Company; testimony dealing with cost allocation and rate design issues.

Expert witness in Case No. 729, The C&P Telephone Company; testimony concerning regulatory and economic treatment of tax expenses in establishing revenue requirements.

Expert witness in Case No. 748, Potomac Electric Power Company; testimony pertaining to requested rate increase.

Expert witness in Formal Case No. 777, Chesapeake & Potomac Telephone Company, testimony dealing with Financial Condition, depreciation and Capital Recovery, and Cost Methods.

Expert witness in Formal Case No. 712, Attrition; testimony dealing with Attrition.

Expert witness in Formal Case No. 785, Potomac Electric Power Company; testimony dealing with company request for rate increase.

Expert witness in Formal Case No. 787, Washington Gas Light Company; testimony concerning WGL's financial condition and revenue increase requirements.

Before the Florida Department of Insurance -

Expert testimony concerning the underwriting return allowable in establishing workers compensation insurance rates.

Before the Florida Public Service Commission -

Expert witness in Docket No. 810035TP, Southern Bell Telephone & Telegraph Company; testimony concerning revenue adjustment to achieve the full normalization of deferred tax expenses and the associated current tax costs.

Expert witness in Docket No. 810095-TP, General Telephone Company; testimony dealing with tax normalization issues.

Expert witness in Docket No. 810235-TP, Central Telephone Company of Florida; testimony dealing with deregulation of telephone terminal equipment.

Before the Circuit Court of the Second Judicial Circuit, State of Florida -

Expert witness in Florida Excess Profits Statute Enforcement; testimony concerning excess profit levels in the private passenger automobile insurance industry in the state of Florida.

Before the Public Service Commission of Georgia -

Expert witness in Docket No. 3231-U, Southern Bell Telephone & Telegraph Company; testimony concerning its relationship with AT&T with respect to general services and licenses, and the proper treatment of the costs involved.

Before the Hawaii Public Utility Commission -

Expert witness in Docket No. 4125, Citizens Electric Company - Kauai Electric Division; testimony concerning rate of return, capital structure and related issues.

Expert witness in Docket No. 4156, Maui Electric Company, Ltd.; testimony concerning rate of return and related issues.

Expert witness in Docket No. 4306, Hawaii Telephone & Telegraph Company; testimony on overall financial health and revenue requirements.

Expert witness in Docket No. 4588, Hawaiian Telephone Company; testimony on cost-based telephone utility rates and flat customer access charges.

Before the Idaho Public Utilities Commission -

Expert witness in Case U-1000-37, Mountain States Telephone & Telegraph Company; testimony concerning rate of return, capital structure and related issues.

Before the Illinois Commerce Commission -

Expert witness in Docket No. 77-0511, Illinois Bell Telephone Company; testimony concerning proposed trunk rates and regulations.

Before the Indiana Public Service Commission -

Expert witness in Cause No. 35214, Public Service of Indiana, Inc.; testimony concerning cost allocation, rate design issues and the economic implications of electric utility rates.

Expert witness, Cause No. 35214, Public Service Company of Indiana; testimony concerning rate structure design and cost allocation issues.

Before the State Corporation Commission of the State of Kansas -

Expert witness in Docket Nos. 105, 712-U; Southwestern Bell Telephone Company; testimony dealing with service and equipment costs, tariff structures and competition in the telecommunications industry.

Before the Utility Regulatory Commission of Kentucky -

Expert witness in Case No. 7669; General Telephone Company of Kentucky; testimony concerning an adjustment in rates.

Expert witness in Case No. 8847, South Central Bell Telephone Company; testimony concerning financial condition, rate base and rate of return.

Before the Louisiana Public Service Commission -

Expert witness in Docket No. U-14495, Gulf States Utilities Company; testimony concerning price elasticity of demand for electric utility service.

Before the Maine Public Utilities Commission -

Expert testimony in F.C. #2168; Central Maine Power Company; testimony concerning electric utility rate structure design.

Expert witness in Docket No. F.C. 2332, Central Maine Power Company; testimony dealing with rate design issues and the economic implications of electric utility rates.

Expert witness in Docket No. 80-142, New England Telephone & Telegraph Company; testimony concerning proposed increase in rates.

Expert witness in Docket No. 80-108, Bangor Hydro-Electric Company; testimony concerning cost of serving an interruptible customer.

Expert witness in Docket No. 80-66, Central Maine Power Company; testimony concerning cost of service and rate design issues.

Before the Maryland Public Service Commission -

Expert testimony in Case No. 6807, Future Adequacy of Service; testimony concerning electric power demand modeling and forecasting.

Expert witness in Case No. 7338, Phase III, Potomac Edison Company; testimony concerning electric utility rate design pertinent to the Public Utility Regulatory Policies Act of 1978.

Expert witness in Case No. 7408, Baltimore Gas & Electric Company; testimony concerning BG&E's Gas Service Tariff provisions regarding the costs to be paid by new customers for gas main extensions and service line extensions in excess of 50 feet.

Expert witness in Case No. 7467, The Chesapeake & Potomac Telephone Company; testimony concerning the regulatory and economic treatment of deferred tax expenses and credits in establishing revenue requirements.

Expert witness in Case No. 7591, Chesapeake & Potomac Telephone Company; testimony dealing with cost methods.

Expert witness in Case No. 7661, Chesapeake & Potomac Telephone Company; testimony concerning the development of cost of service methodologies.

Expert witness in Case No. 7450, Chesapeake & Potomac Telephone Company; testimony concerning issues related to the divestiture of AT&T.

Expert witness in Case No. 7450 Phase II/7735, Chesapeake & Potomac Telephone Company; testimony concerning cost of service and subscriber access costs.

Before the Massachusetts Public Utility Commission -

Expert witness in D.P.U. 19139, Investigation of Rates and Charges for Dimension 400 PBX Service; testimony concerning service and equipment costs; tariff structures and competition in the telecommunications industry.

Expert witness in Docket No. D.P.U. 84-25, Western Massachusetts Electric Company; testimony concerning CWIP in rate base, cash flow and phase-in issues.

Before the Michigan Public Service Commission -

Expert witness for the State of Michigan, Department of Attorney General in Case Nos. U-5365 and U-5322; Michigan Consolidated Gas Company; testimony concerning rate of return and cost of service issues.

Expert witness in Case No. U-5502, Detroit Edison Company; testimony concerning rate of return.

Expert witness of the State of Michigan, Department of Attorney General in Case No. U-5608, Indiana & Michigan Electric Company; testimony concerning rate of return.

Expert witness for the State of Michigan Office of Attorney General in Case No. U-5669, Upper Peninsula Power Company; testimony concerning rate of return and cost of service issues.

Expert witness in Case U-5955, Michigan Consolidated Gas Company; testimony concerning rate of return and capital structure issues.

Expert witness in Case U-6002, Michigan Bell Telephone Company; testimony concerning capital structure and rate of return issues.

Expert witness in Case U-5979, Consumer's Power Company; testimony concerning rate of return issues.

Expert witness in Cases U-5197, U-5752, U-5753 and U-5754, Michigan Bell Telephone Company; testimony concerning cost of service and antitrust issues.

Expert witness in Docket No. U-6103, Detroit Edison Company; testimony concerning cost of service and steam heat rates.

Expert witness in Cause No. U-7660, Detroit Edison Company; testimony concerning financial conditions, revenue requirements and cash flow issues.

Expert witness in Cause No. U-7830, Consumers Power Company; testimony concerning capital structure and rate of return.

Before the Minnesota Public Service Commission -

Expert cost of service and rate design witness in Docket No. E-002/GR-77-611, Northern States Power Company; testimony concerning cost responsibility, cost allocation and principles of rate structure design.

Expert cost of service and rate design witness in Docket No. E002/GR-76-934, Northern States Power Company; testimony concerning cost responsibility and cost allocation issues and principles of rate structure design.

Expert rate design witness in Docket No. ER-2-1, Northern States Power Company; testimony involved analysis of rate design issues including time-of-day pricing, marginal cost responsibility, and load factor analysis.

Expert witness in Docket No. G-008/GR-77-1237, Minnesota Gas Company; testimony concerning cost allocation and rate of return issues.

Before the Mississippi Public Service Commission -

Expert witness in Docket No. U-3929, Mississippi Power Company; testimony concerning proposed increase in rates, and recommendations to a fair rate of return in electric utility rates.

Before the Missouri Public Service Commission -

Expert witness in Docket No. TR82-1998; Southwestern Bell Telephone Company; testimony concerning rate of return requirements.

Expert witness in Case No. TR-83-253, Southwestern Bell Telephone Company; testimony concerning cost of service and subscriber access costs.

Before the Montana Public Service Commission -

Expert witness for the Commission Staff in Docket No. 6279, Montana Power Company; testimony concerning rate structure design, cost of service issues, and rate of return.

Expert witness for the Commission Staff in Docket No. 6277, Montana-Dakota Utilities Company; testimony concerning rate of return, rate structure design and cost of service issues.

Expert witness for the Commission Staff in Docket No. 6441, Montana-Dakota Utilities Company; testimony concerning rate of return issues.

Expert witness for the Consumer Counsel in Docket No. 6454, Montana Power Company; testimony concerning rate of return.

Expert witness for the Consumer Counsel in Docket No. 6496, Mountain States Telephone and Telegraph Company; testimony concerning rate of return and cost of capital.

Expert witness for the Consumer Counsel in Docket No. 6494 and 6495; Butte Water Company; testimony dealing with rate of return and cost of service issues.

Expert witness in Docket Nos. 6545 and 6546, Montana Power Company Water Rates; testimony concerning proposed water rate increases. (Rate of return and cost of service issues.)

Expert witness for the Consumer Counsel in Docket No. 6567, Montana-Dakota Utilities Company; testimony concerning rate of return, cost allocation and rate design issues.

Expert witness in Docket No. 6618, Phase I and Phase II, Montana Power Company; testimony concerning rate of return, capital structure and gas utility rate structure design issues.

Expert witness for the Consumers' Counsel in Docket No. 6701, Great Falls Gas Company; testimony concerning cost of service, cost allocation, and rate design issues.

Expert witness for the Consumer's Counsel in Docket No. 6695, Montana-Dakota Utilities Company; testimony concerning gas and electric rate design and testimony concerning the profits earned by an affiliated coal company.

Expert witness in Docket No. 80.4.2, Montana Power Company, testimony concerning cost of capital and rate of return.

Expert witness in Docket No. 80.7.52, Montana-Dakota Utilities Company; testimony concerning revenue adjustment and the associated current tax costs, and recommendations concerning gas utility rate design.

Expert witness in Docket No. 80.10.79, Mountain States Telephone & Telegraph Company; testimony concerning proposed rate changes and rate structure recommendations.

Expert witness in Docket No. 80.12.100, Mountain States Telephone & Telegraph Company; testimony concerning revenue adjustment and the associated current tax costs, and treatment of affiliate relationship costs.

Expert witness in Docket No. 81.1.2, Montana-Dakota Utilities Company; testimony concerning revenue adjustment and the associated current tax costs, the profits earned by an affiliated coal company, and electric rate structure design.

Expert witness in Docket No. 81.8.70, Pacific Power & Light Company; testimony on rate design and excess coal profits.

Expert witness in Docket No. 82.2.8, Mountain States Telephone Company; testimony dealing with financial conditions and rate of return.

Expert witness on Docket No. 82.8.54, Montana Power Company; testimony dealing with utility captive coal profits and revenue increase needs.

Expert witness in Docket No. 83.3.18, Mountain States Telephone & Telegraph Company; testimony concerning cost of service and access charge matters.

Expert witness in Docket No. 83.3.18, Mountain States Telephone & Telegraph Company; testimony concerning cost of capital, rate of return and cost of service issues.

Reply Comments on Telephone Access Costs and Rates in Docket No. 83.6.47.

Expert witness in Docket No. 83.5.36, Pacific Power and Light Company; testimony concerning coal profit levels.

Expert witness in Docket No. 83.9.67, Montana Power Company; testimony concerning coal profit levels and cost allocation and rate design issues.

Expert witness in Docket No. 83.9.68, Montana-Dakota Utilities Company; testimony concerning coal purchases and operations.

Before the Nebraska Public Service Commission -

Expert witness in Docket No. C-227; Northwestern Bell Telephone Company; testimony concerning rate of return and capital structure issues.

Expert witness in Docket No. 83-707, Nevada Power Company; testimony concerning cost of common equity and rate of return.

Before the New Jersey Department of Public Utilities -

Expert witness in PUC Docket Number 7512-1314; New Jersey Bell Telephone Company; testimony concerning service and equipment costs, tariff structures and competition in the telecommunications industry.

Expert witness in Docket No. 8312-1126, Western Union; testimony concerning competition in intrastate telecommunications.

Before the New Jersey Insurance Department -

Expert witness in Rate Counsel File No. 83-PPA-6, Keystone Insurance Company; testimony concerning the underwriting return on private passenger automobile insurance rates and loss/expense projections.

Before the New Mexico Corporation Commission -

Expert witness in Docket No. 1002, Mountain States Telephone & Telegraph Company; testimony concerning cost of service allocation issues.

Before the State of New York St. Lawrence County Court Commissioners of Appraisal -

Expert witness in Docket No. 79-CV-163, Town of Massena v. Niagara Mohawk Power Corporation; testimony concerning the method of rate base valuation and pricing standards in the electric utility industry.

Before the New York Public Service Commission -

Expert witness for Suffolk County in Case No. 27136; Long Island Lighting Company; testimony dealing with rate of return and cost of service issues.

Presentation regarding telephone customer access line charges and bypass before an en banc meeting of the Public Service Commission, March 1984.

Expert witness in Case No. 27006; New York Telephone Company; expert testimony concerning service and equipment costs, tariff structure and competition in the telecommunications industry.

Expert witness in Cases 26943, 26944, 26945; Niagara Mohawk Power Corporation; expert testimony concerning electric utility costs and rate structure design.

Expert witness in Cases 27374 and 27375; Long Island Lighting Company; testimony concerning electric and gas rate issues.

Expert witness in Docket No. 27774; Long Island Lighting Company; testimony concerning electric utility rate structure design.

Expert witness in Case 27469, New York Bell Telephone Company; testimony concerning terminal equipment rates. Affidavit dealing with the legality of tariffs filed by the Rochester Telephone Corporation.

Before the North Carolina Utility Commission -

Expert witness for the Commission Staff in Docket No. E-22, Sub 224, Virginia Electric & Power Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. E-7, Sub 237, Duke Power Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. P-55, Sub 816; Southern Bell Telephone Company; testimony concerning rate of return and capital structure issues.

Expert witness in Docket No. P100, Sub 65, on behalf of the North Carolina Department of Justice, testimony concerning telephone access charges.

Expert witness in Docket No. E-7, Sub 373, Duke Power Company; testimony concerning rate base and cost of service issues.

Before the North Carolina Insurance Commissioner -

Expert witness on behalf of the North Carolina Insurance Department in Docket No. 361, concerning private passenger automobile insurance rates filed by the North Carolina Insurance Service office.

Expert witness before the Commissioner of Insurance; testimony concerning the allowable underwriting return in farmowners multiple peril insurance rates.

Before the Public Utilities Commission of Ohio -

Expert witness in Case No. 76-26-TP-CCS; Ohio Bell Telephone Company; testimony concerning service and equipment costs, tariff structures and competition in the telecommunications industry.

Expert witness in Case No. 78-676-EL-AIR, Ohio Power Company; testimony concerning rate of return and capital structure issues.

Expert witness in Case No. 79-1184-TP-AIR; Ohio Bell Telephone Company; testimony concerning proper ratemaking treatment of costs and adjustments for demand curtailment and stimulation.

Expert witness in Case No. 80-260-EL-AIR, and 80-429-EL-ATA; Cincinnati Gas & Electric Company; testimony concerning rate structure design, calculation of tariffs and revenue responsibilities.

Expert witness in Case No. 81-782-EL-AIR, Ohio Power & Light Company; testimony on company's request for rate increase.

Expert witness in Case No. 80-1155-GA-AIR et al.; Columbia Gas of Ohio; testimony dealing with rate of return.

Expert witness in Docket No. 83-464-TP-COI, Ohio Bell Telephone Company; testimony concerning intrastate access charges.

Before the Oklahoma Utilities and Transportation Commission -

Expert witness in Case No. 28002, Southwestern Bell Telephone Company; testimony concerning financial condition, cost of capital, rate of return and cost of service issues.

Expert witness in Cause No. 28123, Oklahoma Gas and Electric Company; testimony concerning rate of return CWIP and cash working capital issues.

Expert witness in Cause No. 28002, Southwestern Bell Telephone Company; testimony concerning financial condition, rate of return and cost of service issues.

Before the Ontario Legislative Assembly -

Ontario Hydro Select Committee; expert testimony on economic principles of electric utility rate structure design; March 9, 1976.

Before the Rhode Island Public Utilities Commission -

Expert witness for the Commission Staff in Docket No. 1170; New England Telephone and Telegraph Company; testimony concerning rate of return, working capital allowance, tax issues and earnings erosion.

Expert witness for the Commission Staff in Docket No. 1167; Bristol County Water Company; testimony dealing with rate of

return and the financial implications of leveraged capitalization within a multi-tier holding company structure.

Expert witness for the Commission Staff in Docket No. 1185, Blackstone Valley Electric Company; testimony concerning the principles of electric utility rate structure design.

Expert witness for the Commission Staff in Docket No. 1189, Providence Gas Company; testimony concerning rate of return for a gas utility.

Expert witness for the Division of Public Utilities and Carriers in Docket No. 1268; Newport Electric Corporation; testimony concerning rate of return.

Expert witness for the Division of Public Utilities and Carriers in Docket No. 1251; New England Telephone & Telegraph Company; testimony concerning rate of return.

Expert witness for the Division of Public Utilities and Carriers in Docket No. 1256; Wakefield Water Company; testimony regarding rate of return.

Expert witness for the Division of Public Utilities and Carriers in Docket No. 1258; Providence Gas Company; testimony regarding rate of return and cost of service.

Expert witness in Docket No. 1262, Blackstone Valley Electric Company; testimony presenting and summarizing the results of the Rhode Island Demonstration Project. Expert witness for the Division of Public Utilities and Carriers in Docket No. 1311, Newport Electric Corporation; testimony concerning inverted rates and lifeline rates.

Expert witness in Docket No. 1468, Narragansett Electric Company; testimony consists of a critique of the rate of return testimony presented by the Applicants' witness, and of an analysis of the cost of senior securities and common equity capital.

Expert financial and cost of service witness in Docket No. 1502, Bristol County Water Company; testimony concerning proposed rate increase.

Expert witness in Docket No. 1560, New England Telephone & Telegraph Company; testimony concerning rate of return, affiliated relationships, license contract, migration and related issues.

Before the South Carolina Department of Insurance -

Expert witness in Docket No. 82-053, Insurance Company of North America; testimony concerning the underwriting return for private passenger automobile insurance rates.

Expert witness in Docket No. 83-001; Rate Filing for Private Passenger Automobile Liability and Physical Damage Insurance Rate; testimony concerning rate level requirements for private passenger automobile insurance.

Before the South Carolina Public Service Commission -

Expert witness in Docket No. 80-69-E, Carolina Power & Light Company; testimony concerning rate design issues and the economic implications of electric utility rates and focusing on the PURPA cost of service standard.

Expert witness in Docket No. 82-328-E, Carolina Power & Light Company; testimony concerning rate of return issues.

Before the South Dakota Public Utilities Commission -

Expert witness for the Commission Staff in Docket No. F-3112; Black Hills Power & Light Company; testimony dealing with rate of return, rate structure design, and subsidiary operations.

Expert witness for the Commission Staff in Docket No. F-3053; Montana-Dakota Utilities Company; testimony dealing with rate of return, rate structure design, and subsidiary operations.

Expert witness for the Commission Staff in Docket No. F-3054; Northern States Power Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. F-3055; Northwestern Public Service Company; testimony concerning rate of return.

Expert witness for the Commission staff in Docket No. F-3052; Otter Tail Power Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. F-3126; Montana Dakota Utilities Company; testimony dealing with electric utility rate of return.

Expert witness for the Commission Staff in Docket No. F-3159; Montana-Dakota Utilities Company; testimony dealing with gas utility rate of return.

Expert witness for the Commission Staff in Docket No. F-3153; Northwestern Public Service Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. F-3164; Otter Tail Power Company; testimony concerning rate of return.

Expert witness for the Commission Staff in Docket No. F-3174; Black Hills Power & Light Company; testimony concerning rate of return issues.

Expert witness for the Commission Staff in Docket No. F-3188; Northern States Power Company; testimony concerning rate of return.

Expert witness in Dockets F-3240 and F-3241, Montana-Dakota Utilities Company; testimony concerning rate of return, cost of capital, rate structure design and coal subsidiary profits.

Expert witness in Docket No. F-3262, Black Hills Power & Light Company; testimony concerning rate of return, cost of capital, rate structure design and coal subsidiary profits.

Expert witness in Docket No. F-3367, Northwestern Public Service Company; testimony concerning rate of return and other ratemaking issues.

Expert witness in Docket No. F-3371, Nebraska Public Power District; testimony on proposed MANDAN Nominal 560KV Transmission Facility.

Expert witness in Docket No. F-3370, Montana-Dakota Utilities Company; testimony dealing with rate design.

Expert witness in Docket No. F-3382, Northern States Power Company; testimony on rate of return.

Expert witness in Docket No. F-3384, Montana-Dakota, Utilities Company; testimony on rate of return.

Expert witness in Docket No. F-3389, Black Hills Power & Light Company; testimony on rate of return and cost of service.

Before the Tennessee Public Service Commission -

Expert witness in Docket No. U-6285; South Central Bell Telephone Company; testimony pertaining to Western Electric's cost allocations and anticompetitive implications of South Central Bell's rate levels and rate design for telephone services.

Before the Texas Public Utility Commission -

Expert witness in Docket No. 78; Southwestern Bell Telephone Company; testimony concerning telephone equipment and telephone service costs and rate of design and the economic implications thereof.

Expert witness in Docket No. 3094, General Telephone Company of the Southwest; testimony concerning the application for an adjustment in rates for intrastate telephone service.

Expert witness in Docket 2672, Southwestern Bell Telephone Company; testimony concerning telephone answering service rates proposed by Southwestern Bell.

Before the Texas Railroad Commission -

Expert witness for the City of San Antonio in Docket No. GUD-500; Lo-Vaca Gas Gathering Company; analysis of the economic impact upon purchased gas costs of certain extraordinary transactions.

Before the Public Service Commission of Utah -

Expert witness in Case No. 76-049-01; Mountain States Telephone & Telegraph Company; testimony concerning service and equipment costs, tariff structures and competition in the telecommunications industry.

Expert witness in Case No. 82-049-08; Mountain States Telephone & Telegraph Company; testimony concerning cost of service allocations between service categories and rate of return requirements and capital structure.

Expert witness in Case No. 83-049-05; Mountain States Telephone & Telegraph Company; testimony concerning the need for interim rate relief.

Expert witness in Case No. 84-049-01; Mountain States Telephone & Telegraph Company; testimony concerning post-divestiture cost estimates.

Before the Vermont Public Service Board -

Expert witness in Docket 4299, Central Vermont Power Company; testimony concerning condemnation value and antitrust issues pertaining to the establishment of a municipal electric system in Springfield, Vermont.

Before the Virginia Corporation Commission -

Expert witness in PUE Case No. 790012, testimony concerning rate structure design, analysis of cost structure, revenue responsibilities, time-of-use rates and customer responses.

Before the Washington State Utilities and Transportation Commission -

Expert witness in Case No. U-79-66; Pacific Northwest Bell Telephone Company; testimony concerning rate of return, cost of capital and rate design.

Expert witness in Case No. U-82-19; Pacific Northwest Bell Telephone Company; testimony concerning rate of return and cost allocation issues.

Before the West Virginia Public Service Commission -

Expert witness in PSC Case Nos. 8500, 8750, and 8879; Chesapeake & Potomac Telephone Company of West Virginia; testimony concerning service and equipment costs, tariff structures and competition in the telecommunications industry.

Before the Public Service Commission of Wisconsin -

Expert witness in File Number 6720-TR-10; Wisconsin Telephone Company; testimony concerning service and equipment costs, tariff structure and competition in the telecommunications industry.

Expert witness in I-AC-15, WPSC Internal Wiring Proceeding; testimony concerning pricing standards for the sale of inside wiring.

Expert witness in Docket No. 6720-TR-34B, Wisconsin Telephone Company; testimony concerning Optional Local Measured Service.

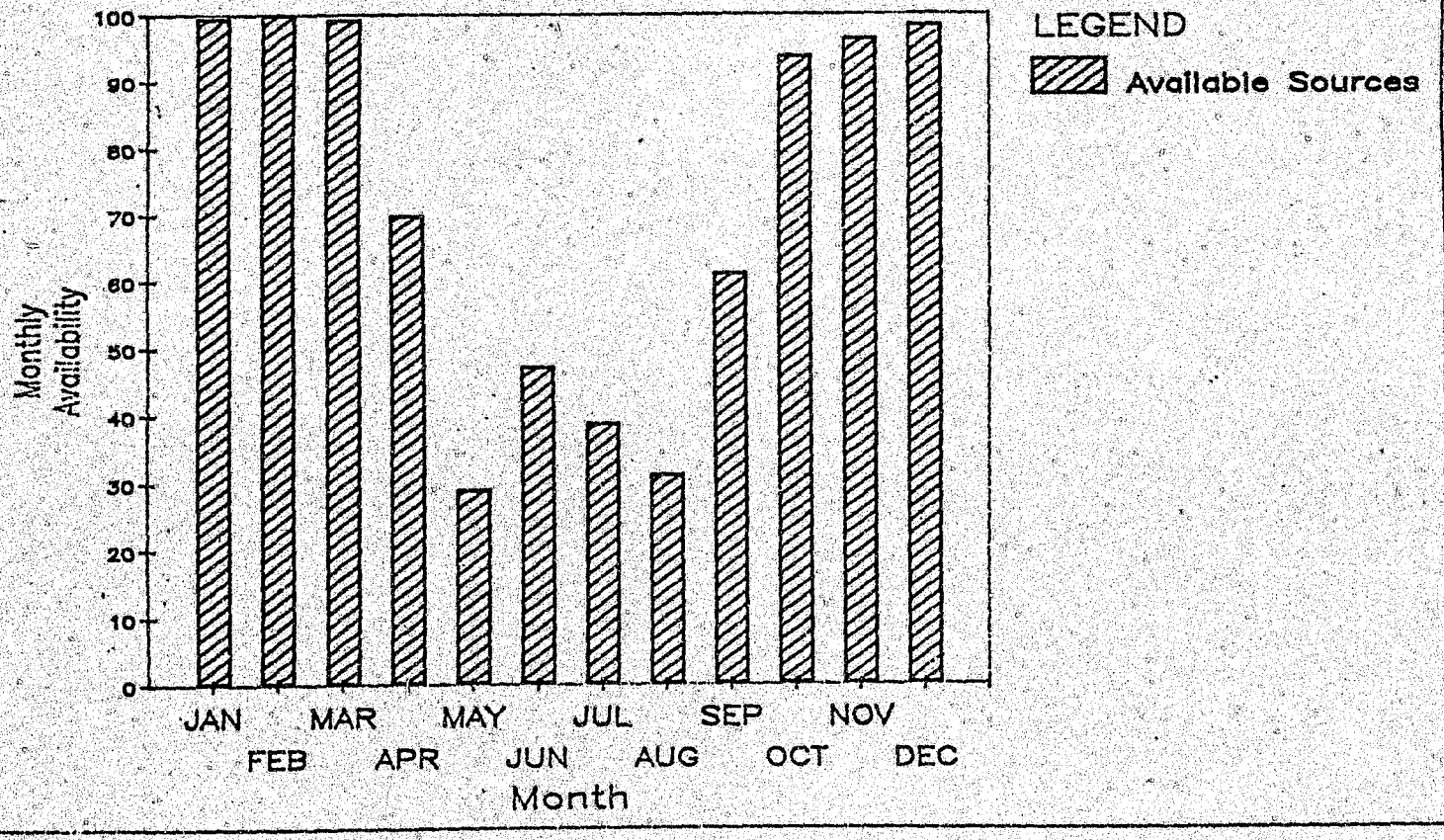
Docket No. R-850152
Exhibit__(J.W.-2)

Q. IR-Staff-LIM-3. Provide a schedule and graph showing when, during the average flow year, Limerick 1 will be able to operate with the water supply as it presently exists.

A. IR-Staff-LIM-3. See attached graph, which reflects only those sources, allocations and standards that are approved and in use currently. This graph does not reflect any planned maintenance outages that may occur during times of water unavailability nor does it take into account any modification of the current standards, nor any additional sources such as those set forth in response to DR-Staff-Lim-8.

Responsible Witness: V. S. Boyer, Senior Vice President, Nuclear Power

WATER AVAILABILITY — LIMERICK 1



PHILADELPHIA ELECTRIC COMPANY

Ranking of General Electric Nuclear Units Based on Average Capacity Factor 1977-1984

	Unit Name	Date of Commercial Operation	1984 Net Dependable Capability (MW)	Average Capacity Factor
1.	WPPSS	12/13/84	1,100	84.8
2.	Vermont Yankee	11/30/72	504	76.8
3.	LaSalle 2	10/19/84	1,036	75.7
4.	Millstone 1	3/1/71	654	72.7
5.	Monticello	6/30/71	525	68.0
6.	Susquehanna 1	6/8/83	1,032	67.8
7.	Dresden 2	6/9/70	772	64.9
8.	Peach Bottom 3	12/23/74	1,035	64.2
9.	Quad Cities 1	2/18/73	769	64.1
10.	Cooper Station	7/1/74	764	63.7
11.	Big Rock Point	3/29/63	70	63.2
12.	Browns Ferry 2	3/1/75	1,065	63.2
13.	Browns Ferry 1	8/1/74	1,065	62.6
14.	Quad Cities 2	3/10/73	769	61.8
15.	Fitzpatrick	7/28/75	810	61.3
16.	Nine Mile Point 1	12/1/69	610	60.3
17.	Dresden 3	11/16/71	773	59.3
18.	LaSalle 1	1/1/84	1,036	57.2
19.	Peach Bottom 2	7/5/74	1,051	57.0
20.	Pilgrim 1	12/1/72	663	56.2
21.	Hatch 1	12/31/75	752	55.9
22.	Browns Ferry 3	3/1/77	1,065	55.6
23.	Hatch 2	9/5/79	748	54.0
24.	Duane Arnold	2/1/75	515	53.6
25.	Brunswick 1	3/18/77	790	49.4
26.	Oyster Creek	12/1/69	620	42.6
27.	Brunswick 2	11/3/75	790	42.0

Source: Nuclear Regulatory Commission: Licensed Operating Reactors.

PHILADELPHIA ELECTRIC COMPANY

Ranking of Westinghouse Nuclear Units Based on
Average Capacity Factor
1977-1984

	Unit Name	Date of Commercial Operation	1984 Net Dependable Capability (MW)	Average Capacity Factor
1.	Callaway 1	12/19/84	1,120	95.3
2.	Prairie Island 2	12/21/74	500	85.4
3.	Farley 2	7/30/81	809	85.3
4.	Prairie Island 1	12/16/73	503	83.0
5.	Point Beach 2	10/1/72	485	82.7
6.	Kewaunee	6/16/74	503	82.1
7.	Haddam Neck	1/1/68	569	82.1
8.	McGuire 2	3/1/84	1,180	75.7
9.	Ginna	7/1/70	470	73.5
10.	Point Beach 1	12/21/70	485	68.8
11.	Cook 1	8/27/75	1,020	66.2
12.	Sequoyah 2	6/1/82	1,148	65.4
13.	North Anna 1	12/14/80	890	65.1
14.	Turkey Point 3	12/14/72	666	65.0
15.	Yankee-Rowe 1	7/1/61	167	64.9
16.	Turkey Point 4	9/7/73	666	64.0
17.	Cook 2	7/1/78	1,060	64.0
18.	Zion 2	9/17/74	1,040	62.8
19.	Farley 1	12/1/77	797	62.0
20.	Zion 1	12/31/73	1,040	61.2
21.	Surry 2	5/1/73	775	60.0
22.	Sequoyah 1	7/1/81	1,148	59.7
23.	North Anna 1	6/6/78	890	58.7
24.	Indian Point 2	8/1/74	864	57.7
25.	Summer 1	1/1/84	885	54.0
26.	Surry 1	12/22/72	775	53.7
27.	Robinson 2	3/7/71	665	53.0
28.	Trojan	5/20/76	1,080	52.2
29.	McGuire 1	12/1/81	1,180	49.5
30.	Salem 1	6/30/77	1,079	45.2
31.	Indian Point 3	8/30/76	965	44.4
32.	Beaver Valley 1	10/1/76	810	44.0
33.	Salem 2	10/13/81	1,106	43.3
34.	San Onofre 1	1/1/68	436	35.1

PHILADELPHIA ELECTRIC COMPANY

Ranking Combustion Engineering Nuclear Units Based on Average Capacity Factor
1977-1984

	Unit Name	Date of Commercial Operation	1984 Net Dependable Capability (MW)	Average Capacity Factor
1.	St. Lucie 2	8/8/83	786	82.4
2.	Calvert Cliffs 2	12/21/76	825	78.0
3.	Calvert Cliffs 1	6/20/74	825	72.5
4.	Maine Yankee	4/1/77	810	71.0
5	Fort Calhoun 1	5/8/75	478	67.9
6.	St. Lucie 1	12/28/72	822	67.3
7.	Millstone 2	12/31/71	833	64.6
8.	Arkansas 2	3/26/80	858	62.5
9.	San Onofre 3	4/1/84	1,080	57.5
10.	San Onofre 2	8/8/83	1,070	56.0
11.	Palisades	12/26/75	635	55.9

Source: Nuclear Regulatory Commission, Licensed Operating Reactors.

PHILADELPHIA ELECTRIC COMPANY

Average Annual Capacity Factors For Nuclear Units 1/

Year	General Electric	Combustion Engineering	Westinghouse
1977	59.5	76.2	68.9
1978	68.6	67.6	66.5
1979	68.2	67.4	55.2
1980	60.2	64.9	59.0
1981	59.0	70.9	61.9
1982	59.2	69.7	59.2
1983	54.3	61.3	59.1
1984	49.8	67.4	60.9
Average 1977-1984	59.8	68.2	61.3
Average 1980-1984	56.5	66.8	60.0

1/ Capacity Factor =

$$\frac{\text{Net Electricity Generated}}{(\text{Number of Hours in Reporting Period} \times \text{Net Dependable Capability})}$$

Source: Nuclear Regulatory Commission, Licensed Operating Reactors.

PHILADELPHIA ELECTRIC COMPANY

Forecasted Performance of Philadelphia Electric Company Nuclear Units

Year [1]	MW Capacity [2]	MWH Generated [2]	Annual Capacity Factor (%)
1987	2,863.84	15,339,242	61.1
1988	2,863.84	14,644,392	58.4
1989	2,863.84	16,464,261	65.6
1990	2,863.84	15,485,969	61.7

1/ Year ended June 30.

2/ Exhibit JJC-1, PECO Statement No. 22A.

PHILADELPHIA ELECTRIC COMPANY

Forecasted Generation Mix of Philadelphia Electric Company (MWH)

	YEAR			
	1987	1988	1989	1990
Total Power Requirements	30,286,494	30,249,847	30,608,469	30,890,962
Sources				
Nuclear	15,339,242	14,644,392	16,464,261	15,485,969
Coal	7,292,000	7,007,168	6,929,484	6,941,932
Oil	1,749,000	2,384,490	2,277,022	2,135,145
Peaking	130,260	130,260	130,260	130,260
Pumped Storage (Net)	(538,000)	(577,744)	(577,744)	(577,744)
Firm Purchases	2,079,000	2,168,075	2,260,965	2,357,836
Interchange Purchases	3,819,992	4,129,625	2,814,062	4,162,916
Interchange Sales	(1,317,000)	(1,368,417)	(1,421,842)	(1,477,352)
Hydro	1,732,000	1,732,000	1,732,000	1,732,000
Total	30,286,494	30,249,847	30,608,469	30,890,962

PHILADELPHIA ELECTRIC COMPANY

Reward/Penalty Based on Company Assuming
All of the Burden of Cost Recovery and Equal
Sharing of Superior Performance
($ million)

	Year			
Performance	1987	1988	1989	1990
55% Capacity Factor	(37.1)	(40.3)	(45.1)	(48.2)
75% Capacity Factor	10.9	12.5	16.9	16.2

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
75% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,644,392	16,464,261	15,485,969
Nuclear Generation at 80% Capacity Factor (MWH)	18,815,428	18,815,428	18,815,428	18,815,428
Net Generation Change (MWH)	3,476,186	4,171,036	2,351,167	3,329,459
Unit Cost of Nuclear Generation (mills/kwh)	8.74	7.80	8.04	7.95
Change in Nuclear Fuel Cost	30,381,874	32,534,089	18,903,391	26,469,207
Change in Oil Generation (MWH)	(545,376)	(1,180,866)	(1,073,398)	(931,521)
Unit Cost of Oil Generation (mills/kwh)	54.54	57.15	62.74	66.45
Change in Oil Fuel Cost	(29,744,807)	(67,486,492)	(67,344,991)	(61,899,570)
Change in Interchange Purchases (MWH)	(2,930,871)	(2,990,171)	(1,277,770)	(2,397,939)
Unit Price of Inter-change Purchases (Mills/KWH)	30.65	32.80	35.09	37.55
Change in Purchases Costs	(89,829,357)	(98,077,609)	(44,836,949)	(90,042,609)
Net Change in Fuel Costs	(89,192,290)	(133,030,012)	(93,278,549)	(125,472,973)

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
70% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,644,392	16,464,261	15,485,969
Nuclear Generation at 70% Capacity Factor (MWH)	17,561,067	17,561,067	17,561,067	17,561,067
Net Generation Requirements (MWH)	2,221,825	2,916,675	1,096,806	2,075,098
Unit Cost of Nuclear Generation (mills/kwh)	8.74	7.80	8.04	7.95
Change in Nuclear Fuel Cost	19,418,751	22,750,065	8,818,320	16,497,029
Change in Oil Generation (MWH)	(545,376)	(1,180,866)	(1,073,398)	(931,521)
Unit Cost of Oil Generation (mills/kwh)	54.54	57.15	62.74	66.45
Change in Oil Fuel Cost	(29,744,807)	(67,486,492)	(67,344,991)	(61,899,570)
Change in Interchange Purchases (MWH)	(1,676,449)	(1,735,809)	(23,408)	(1,143,577)
Unit Price of Interchange Purchases (mills/kwh)	34.05	36.44	38.99	41.72
Change in Purchases Costs	(57,083,088)	(63,252,880)	(912,678)	(47,710,032)
Change in Fuel Costs	(67,409,145)	(107,989,307)	(59,439,348)	(93,112,574)

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
60% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,644,392	16,464,261	15,485,969
Nuclear Generation at 60% Capacity Factor (MWH)	15,052,343	15,052,343	15,052,343	15,052,343
Net Generation Requirements (MWH)	(286,899)	407,951	(1,411,918)	(433,626)
Unit Cost of Nuclear Generation (mills/kwh)	8.74	7.80	8.04	7.95
Change in Nuclear Fuel Cost	(2,507,497)	3,182,018	(11,351,821)	(3,447,327)
Change in Local Coal Generation (MWH)	143,450	(203,976)	705,959	216,813
Unit Cost of Local Coal Generation (mills/kwh)	22.01	22.74	25.30	26.25
Change in Local Coal Fuel Cost	3,157,323	(4,638,403)	17,860,763	5,691,341
Change in Oil Generation (MWH)	143,450	(203,976)	705,959	216,813
Unit Cost of Oil Generation (mills/kwh)	54.54	57.15	62.74	66.45
Change in Oil Fuel Cost	7,823,736	(11,657,200)	44,291,868	14,407,224
Net Change in Fuel Cost	8,473,562	(13,113,585)	50,800,810	16,651,238

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
55% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,644,392	16,464,261	15,485,969
Nuclear Generation at 55% Capacity Factor (MWH)	13,797,891	13,797,891	13,797,891	13,797,891
Net Generation Requirements (MWH)	(1,541,351)	(846,501)	(2,666,370)	(1,688,078)
Unit Cost of Nuclear Generation (mills/kwh)	8.74	7.80	8.04	7.95
Change in Nuclear Fuel Cost	(13,471,408)	(6,602,708)	(21,437,615)	(13,240,220)
Change in Local Coal Generation (MWH)	770,676	423,251	1,333,185	844,039
Unit Cost of Local Coal Generation (mills/kwh)	22.01	22.74	25.30	26.25
Change in Local Coal Fuel Cost	16,962,568	9,624,716	33,729,581	22,156,024
Change in Oil Generation (MWH)	770,676	423,251	1,333,185	844,039
Unit Cost of Oil Generation (mills/kwh)	54.54	57.15	62.74	66.45
Change in Oil Fuel Cost	42,032,642	24,188,766	83,644,027	56,086,392
Net Change in Fuel Cost	45,523,802	27,210,775	95,935,993	64,822,195

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Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY

Forecasted Performance of Philadelphia Electric Company Nuclear Units

Year 1/	MW Capacity 2/	MWH Generated 2/	Annual Capacity Factor (%)
1987	2,863.84	15,339,242	61.1
1988	2,863.84	14,718,978	58.7
1989	2,863.84	16,508,673	65.8
1990	2,863.84	15,485,968	61.7

1/ Year ended June 30.

2/ Exhibit JJC-1, PECO Statement No. 22A.

PHILADELPHIA ELECTRIC COMPANY

Forecasted Generation Mix of
Philadelphia Electric Company (MWH)

	YEAR			
	1987	1988	1989	1990
Total Power Requirements	30,286,494	30,439,070	30,722,285	30,952,702
Sources				
Nuclear	15,339,242	14,718,978	16,508,673	15,485,968
Coal	7,292,000	7,010,000	7,116,000	7,138,857
Oil	1,749,000	2,389,000	2,281,000	2,135,145
Peaking	130,260	149,200	140,120	140,120
Pumped Storage (Net)	(538,000)	(574,000)	(539,000)	(539,000)
Firm Purchases	2,079,000	1,841,000	1,610,000	1,610,000
Interchange Purchases	3,819,992	4,409,892	3,641,492	4,918,436
Interchange Sales	(1,317,000)	(1,243,000)	(1,771,000)	(1,671,824)
Hydro	1,732,000	1,738,000	1,735,000	1,735,000
Total	30,286,494	30,439,070	30,722,285	30,952,702

PHILADELPHIA ELECTRIC COMPANY

Reward/Penalty Based on Company Assuming
All of the Burden of Cost Recovery and Equal
Sharing of Superior Performance
($ million)

	Year			
Performance	1987	1988	1989	1990
55% Capacity Factor	(37.1)	(41.4)	(48.5)	(51.4)
75% Capacity Factor	13.6	15.5	18.3	19.2

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
75% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,718,978	16,508,673	15,485,968
Nuclear Generation at 75% Capacity Factor (MWH)	18,815,428	18,815,428	18,815,428	18,815,428
Net Generation Change (MWH)	3,476,186	4,096,450	2,306,755	3,329,459
Unit Cost of Nuclear Fuel Cost	7.52	6.47	6.77	7.07
Change in Nuclear Fuel Cost	26,140,919	26,504,032	15,616,731	23,539,275
Change in Coal Generation (MWH)	(347,619)	(404,645)	(230,676)	(332,946)
Unit Cost of Coal Generation (mills/kwh)	21.22	22.74	24.63	26.54
Change in Coal Fuel Cost	(7,376,467)	(9,315,327)	(5,681,538)	(8,836,384)
Change in Oil Generation (MWH)	(347,619)	(404,645)	(230,676)	(332,946)
Unit Cost of Oil Generation (mills/kwh)	55.95	58.30	64.10	68.59
Change in Oil Fuel Cost	(19,449,261)	(23,882,304)	(14,786,300)	(22,836,759)
Change in Interchange Purchases (MWH)	(2,780,949)	(3,277,160)	(1,845,404)	(2,663,567)
Unit Price of Inter-chnge Purchases (mills/kwh)	29.75	32.91	35.53	38.82
Change in Purchases Costs	(82,744,351)	(107,861,167)	(65,570,895)	(103,391,688)
Net Change in Fuel Costs	(83,429,159)	(114,554,766)	(70,422,001)	(111,525,556)

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
70% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,718,978	16,508,673	15,485,969
Nuclear Generation at 70% Capacity Factor (MWH)	17,561,067	17,561,067	17,561,067	17,561,067
Net Generation Requirements (MWH)	2,221,825	2,842,089	1,052,394	2,075,098
Unit Cost of Nuclear Generation (mills/kwh)	7.52	6.47	6.77	7.07
Change in Nuclear Fuel Cost	16,708,124	18,388,316	7,124,707	14,670,943
Change in Coal Generation (MWH)	(222,183)	(284,209)	(105,239)	(207,510)
Unit Cost of Coal Generation (mills/kwh)	21.22	22.74	24.63	26.54
Change in Coal Fuel Cost	(4,714,713)	(6,462,910)	(2,592,046)	(5,507,310)
Change in Oil Generation (MWH)	(222,183)	(284,209)	(105,239)	(207,510)
Unit Cost of Oil Generation (mills/kwh)	55.95	58.30	64.10	68.59
Change in Oil Fuel Cost	(12,431,111)	(16,569,379)	(6,745,846)	(14,233,097)
Change in Interchange Purchases (MWH)	(1,777,460)	(2,273,671)	(841,915)	(1,660,078)
Unit Price of Interchange Purchases (mills/kwh)	31.41	34.74	37.51	40.97
Change in Purchases Costs	(55,824,686)	(78,990,748)	(31,576,871)	(68,019,222)
Change in Fuel Costs	(56,262,386)	(83,634,721)	(33,790,056)	(73,088,697)

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
60% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,718,978	16,508,673	15,485,969
Nuclear Generation at 60% Capacity Factor (MWH)	15,052,343	15,052,343	15,052,343	15,052,343
Net Generation Requirements (MWH)	(286,899)	333,365	(1,456,330)	(433,626)
Unit Cost of Nuclear Generation (mills/kwh)	7.52	6.47	6.77	7.07
Change in Nuclear Fuel Cost	(2,157,480)	2,156,872	(9,859,354)	(3,065,736)
Change in Local Coal Generation (MWH)	28,690	(33,337)	145,633	43,363
Unit Cost of Local Coal Generation (mills/kwh)	21.22	22.74	24.63	26.54
Change in Local Coal Fuel Cost	608,800	(758,072)	3,586,941	1,150,843
Change in Oil Generation (MWH)	28,690	(33,337)	145,633	43,363
Unit Cost of Oil Generation (mills/kwh)	55.95	58.30	64.10	68.59
Change in Oil Fuel Cost	1,605,200	(1,943,518)	9,335,075	2,974,241
Change in Inter-change Purchass (MWH)	229,519	(266,692)	1,165,084	346,901
Unit Cost of Interchange Purchases (mills/kwh)	34.71	36.57	41.45	45.29
Change in Interchange Purchase Costs	7,967,300	(9,752,926)	48,296,563	15,709,923
Net Change in Fuel Cost	8,023,819	(10,297,645)	51,359,225	16,769,271

PHILADELPHIA ELECTRIC COMPANY

Change in Fuel Costs Based on
55% Capacity Factor Achieved by PECO Nuclear Units

	YEAR			
	1987	1988	1989	1990
Actual Nuclear Generation (MWH)	15,339,242	14,718,978	16,508,673	15,485,969
Nuclear Generation at 55% Capacity Factor (MWH)	13,797,891	13,797,891	13,797,891	13,797,891
Net Generation Requirements (MWH)	(1,541,351)	(921,087)	(2,710,782)	(1,688,078)
Unit Cost of Nuclear Generation (mills/kwh)	7.52	6.47	6.77	7.07
Change in Nuclear Fuel Cost	(11,590,960)	(5,959,433)	(18,351,994)	(11,934,711)
Change in Local Coal Generation (MWH)	154,135	92,109	271,078	168,808
Unit Cost of Local Coal Generation (mills/kwh)	21.22	22.74	24.63	26.54
Change in Local Coal Fuel Cost	3,270,747	2,094,552	6,676,656	4,480,159
Change in Oil Generation (MWH)	154,135	92,109	271,078	168,808
Unit Cost of Oil Generation (mills/kwh)	55.95	58.30	64.10	68.59
Change in Oil Fuel Cost	8,623,859	5,369,937	17,376,113	11,578,527
Change in Interchange Purchases (MWH)	1,233,081	736,870	2,168,626	1,350,462
Unit Cost of Interchange Purchases (mills/kwh)	36.37	40.23	43.43	47.44
Change in Interchange Purchase Costs	44,842,216	29,642,053	94,179,073	64,069,988
Net Change in Fuel Cost	45,145,863	31,147,110	99,879,847	68,193,962

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
PECO's Phase-In Proposal

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.5	2.6	2.8	3.1
Excluding AFUDC	1.5	2.0	2.3	2.8
Cash/Capital	.8%	2.8%	4.2%	5.3%
Cash/Construction	12%	36%	59%	92%
Debt Leverage	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1986

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.5	2.6	2.6	2.9	2.6
Excluding AFUDC	1.5	1.6	1.6	2.1	1.9
Cash/Capital	0.8%	0.1%	0.2%	2.4%	1.0%
Cash/Construction	12%	1%	3%	38%	16%
Debt Leverage	50%	50%	50%	50%	50%

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Corrected

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1987

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.6	2.4	2.4	2.9	2.4
Excluding AFUDC	2.0	1.6	1.6	2.6	2.0
Cash/Capital	2.8%	1.0%	1.1%	4.9%	2.2%
Cash/Construction	36%	13%	15%	62%	28%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1988

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.8	2.4	2.5	2.8	2.3
Excluding AFUDC	2.3	1.7	1.7	2.4	2.0
Cash/Capital	4.2%	1.1%	1.4%	3.9%	1.6%
Cash/Construction	59%	17%	20%	53%	23%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1989

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	3.1	2.5	2.6	2.9	2.4
Excluding AFUDC	2.8	1.8	1.9	2.4	1.9
Cash/Capital	5.3%	1.8%	2.1%	3.2%	1.5%
Cash/Construction	92%	34%	39%	56%	26%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
Combination Sinking Fund and Phase-In

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.7	2.6	2.7	2.9
Excluding AFUDC	1.7	1.9	2.1	2.4
Cash/Capital	.4%	1.8%	2.5%	3.9%
Cash/Construction	7%	24%	36%	70%
Debt Leverage	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
Combination Sinking Fund and Phase-In

	1986	1987	1988	1989
EFFICIENT OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.6	2.6	2.7	2.8
Excluding AFUDC	1.7	2.0	2.1	2.4
Cash/Capital	.5%	1.9%	2.7%	4.0%
Cash/Construction	8%	25%	39%	72%
Debt Leverage	50%	50%	50%	50%
POOR OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.6	2.5	2.6	2.8
Excluding AFUDC	1.7	1.9	2.0	2.3
Cash/Capital	.2%	1.4%	2.0%	3.3%
Cash/Construction	3%	19%	30%	60%
Debt Leverage	50%	50%	50%	50%

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-850152
Philadelphia Electric Company	)	

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FEB 24 1986

DIRECT

TESTIMONY AND EXHIBITS

OF

DR. JOHN W. WILSON

FOLDER

January 1986

GEC Statement No. 1B

J. W. WILSON & ASSOCIATES, INC.
ECONOMIC COUNSEL
THIRD FLOOR • WATERGATE OFFICE BUILDING
2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-850152
	)	
Philadelphia Electric Company	)	
	)	

DIRECT TESTIMONY

OF

DR. JOHN W. WILSON

January 1986

GEC Statement No. 1B

J. W. WILSON & ASSOCIATES, INC.
ECONOMIC COUNSEL
THIRD FLOOR • WATERGATE OFFICE BUILDING
2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	
	)	Docket No. R-850152
Philadelphia Electric Company	)	
	)	

Direct Testimony of John W. Wilson

I. Qualifications and Experience

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 2600 Virginia Avenue, N.W., Washington, D.C. 20037.

Q. WERE YOUR QUALIFICATIONS SET FORTH PREVIOUSLY IN THIS PROCEEDING?

A. Yes. My qualifications and resume are contained in GEC Statement No. 1A.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. I have been asked by the Staff of the Governor's Energy Council to present the results of my analysis of possible rate phase-in options for the costs of Philadelphia Electric Company's (PECO) Limerick 1 nuclear unit. This testimony, and the accompanying exhibits, summarizes the results of that analysis and addresses the earnings and cash flow effects on PECO under the various phase-in options. It shows that the Commission should consider the possibility that rates can be raised less dramatically than the Company contemplates under its phase-in proposal.

In short, the purpose of my testimony in this proceeding is to set forth the reasons for, and illustrate the results of, alternative ratemaking procedures that the Commission may wish to consider adopting in order to reduce the potential ratepayer burden that is otherwise likely to result from the addition of the Limerick 1 nuclear generating unit to PECO's rate base in this proceeding.

III. Financial Condition

Q. HAVE YOU MADE AN ANALYSIS TO DETERMINE WHETHER A PHASE-IN OF THE ALLOWABLE COSTS OF THE LIMERICK 1 UNIT COULD BE SUSTAINED FINANCIALLY BY PECO?

A. Yes, I have. My analysis shows that the Company's current rates are covering all operating expenses as well as interest and dividend requirements and, in addition, they are providing a substantial contribution toward the internal financing of construction expenditures. Assuming that the full capitalized costs of constructing Limerick 1 are found to be includable in rate base under the appropriate "used and useful" and "prudence" tests, current rate increases of the full magnitude that would be necessary under conventional ratemaking in conjunction with commercial operation of the unit are not essential in order to sustain operations or to permit the completion of the Company's current generation construction program.

Q. WHAT RETURN ON AVERAGE COMMON EQUITY DID THE COMPANY REALIZE UNDER EXISTING RATES IN CALENDAR YEAR 1984?

A. Net income as a percentage of average common equity capital rose to 15.0 percent in 1984. That is a higher rate of earnings than was posted over the same period by most other electric utilities and firms in other sectors of the economy.

As shown in Exhibit___(J.W.-7), an examination of PECO's earned return in 1984, and also the Company's internal cash flow, including cash income, depreciation, deferred taxes and investment tax credits, shows that PECO had earnings and cash flow that were more than adequate to meet all current operating cash needs including interest and dividend requirements. PECO also had total interest coverage of 2.7 times and first mortgage bond coverage of 2.5 times. This coverage level is sufficient to support an investment grade bond rating.

Q. DO THE BOOK RETURNS SHOWN IN EXHIBIT___(J.W.-7), ADEQUATELY REFLECT THE ACTUAL CASH FLOW THAT IS AVAILABLE TO PECO UNDER THE COMPANY'S PRESENT RATES?

A. No. Book returns do not recognize items such as depreciation and amortization expenses (which produce revenues but involve no current cash outlay), and

investment tax credits and deferred taxes (which result from accelerated depreciation). Generally, effective cash flow is considerably greater than book return. For example, while PECO recorded $130.3 million of income taxes on its books as an electric utility operating expense in calendar year 1984, the Company actually paid only $4.2 million of this amount in income taxes currently because of various deductions and credits such as investment tax credits, accelerated depreciation, expense write-offs and other devices.

Q. IN COMPUTING THE RETURN AND CASH FLOW FIGURES SHOWN IN EXHIBIT__(J.W.-7), HAVE YOU MADE ANY ADJUSTMENTS TO THE COMPANY'S ACTUAL BOOK OPERATING RESULTS?

A. No.

IV. PECO's Phase-In Proposal

Q. PLEASE EXPLAIN THE COMPANY'S PHASE-IN PROPOSAL.

A. PECO has requested a $670.7 million base rate increase in this proceeding. The increase consists of three parts. First of all, a rate increase of $848.7 million is requested to cover the carrying costs of Limerick 1

and all of Limerick common plant. The second part is a base rate decrease of $207.5 million, which reflects expected fuel savings. The remainder of the increase is $29.5 million, and is attributed by PECO to rate of return, non-Limerick rate base and operating and maintenance expenses factors, offset by sales growth.

Limerick	$848.7
Other	29.5
Fuel Savings	(207.5)
Base Rate Increase	$670.7

Under PECO's phase-in proposal the total rate increase requested in this case of $670.7 million would be phased-in over three years in equal annual installments and the amount of the deferred revenues would be collected from ratepayers in equal amounts in years four, five, and six. No recovery of return on the deferred revenue balance is contemplated by PECO's proposal. As discussed in Section VI of my testimony, the disallowance of a return on these deferred revenues would cause a write-off for financial accounting purposes under the recent proposed amendment to Financial Accounting Standards Board (FASB) Statement 71 published on December 19, 1985. The amount of the write-off under PECO's proposal would be equal to the present value of the disallowed return amounts.

Q. WHAT ARE THE SPECIFICS OF THE COMPANY'S PROPOSED BILLING PROCEDURE?

A. If the Commission were to approve PECO's entire request for $670.7 million in additional base rate revenues, the Company would file tariffs to produce this revenue increase together with phase-in adjustment factors which could be applied to each rate schedule during the first two years of the phase-in period. The third year would reflect the full amount of the rate increase.

In years one and two PECO would calculate the total revenue that would be billed to each customer class under the approved tariff rate and under the rates produced by the phase-in adjustment factors. The difference between the two revenue amounts would be booked as unbilled revenue and recovered from the respective customer classes in years four, five, and six by the addition of an adjustment factor to the rates then in effect.

Q. IS THE AMOUNT AND TIMING OF THE REVENUE DEFERRAL IN PECO'S PROPOSAL DEPENDENT ON THE LEVEL OF RATE INCREASE GRANTED BY THIS COMMISSION?

A. Yes. PECO proposes that if the Commission alters the Company's proposed allowed rate of return or makes other adjustments that would grant a lower total amount of increased revenue than has been requested, that the third year revenue increase would be reduced first, the second year revenue increase second, and the first year revenue increase last. Therefore, a reduction in the total revenue increase sought by PECO by one-third could result in a two year phase-in and two year recovery period instead of a three year phase-in and three year recovery period.

PECO's methodology thus has appeal from the Company's perspective because even if the entire requested revenue is not granted, the first year rate increase would still be 9.4 percent. To the extent that PECO does not receive all of its request, the amount denied would be applied to the phase-in increases in the second and third years.

V. Rationale for Alternative Ratemaking Proposals

Q. DO YOU RECOMMEND THAT THE COMMISSION CONSIDER ALTERNATIVE RATE BASE AND STRAIGHT LINE DEPRECIATION TREATMENT OF LIMERICK 1 IN THIS CASE?

A. Yes. Conventional rate base treatment and straight line depreciation result in a heavy loading of costs and rates during the early years of a plant's operating life. Assuming constant capital costs and tax rates, the annual revenue requirement associated with the capital investment in a plant decreases over time as depreciation accruals are deducted from original cost. Consequently, the front-loaded capital costs fall heavily upon system ratepayers during the early years even though the functional utility of the plant extends over the life of the facility. Furthermore, the declining cost signal associated with conventional rate base treatment runs counter to price trends throughout most of the economy during periods of inflation. Moreover, cash flow to the utility under the traditional approach is highest during the early years of the plant's operation and approaches zero at the end of the service life when replacement of the facility

requires capital or cash flow. Exhibit___ (J.W.-8) shows estimated annual revenue requirement over the life of Limerick 1 under conventional rate treatment.

The $842.3 million first year revenue requirement shown on Exhibit___ (J.W.-8) is different from the $848.7 million Limerick 1 amount included in PECO's $670.7 million base rate request. This difference is caused by differences in the calculations underlying the two values. For example, Exhibit___ (J.W.-8) assumes a return on average rate base, whereas PECO's return calculation is on a beginning of year rate base. This difference is offset in part by PECO's assumption that the beginning of year rate base is net of accumulated depreciation for the the first 4.5 months of the plant's life and of accumulated deferred income taxes accrued since 1985. Exhibit___ (J.W.-8) also uses the ACRS rates for 10 year recovery property, whereas PECO has used a composite rate. PECO's calculation also includes the amortization of investment tax credits taken in 1986 that relate to other electric plant in its Limerick revenue requirement. Finally, PECO's first year revenue requirement calculations include nuclear fuel and cash working capital in rate base,

whereas the rate base used to develop the rate increases shown on Exhibit___ (J.W.-8) does not.

Q. WHAT SPECIFIC RATEMAKING ALTERNATIVES TO THE TRADITIONAL METHOD DO YOU PROPOSE IN THIS CASE?

A. I present three specific ratemaking alternatives for consideration by the Commission: (1) phase-in and deferred income method for Limerick 1; (2) sinking fund depreciation rates for Limerick 1; and, (3) levelized real capital cost recovery (or trended rate base) method for Limerick 1. Three variations of the phase-in and deferral approach (including PECO's proposal) are illustrated in my testimony, as well as a combination of the phase-in and deferral approach with the sinking fund depreciation method. I have listed these various ratemaking approaches and the variations presented in my testimony on Exhibit___ (J.W.-10)

Q. ARE THERE CERTAIN REGULATORY OBJECTIVES WHICH ARE ADVANCED BY EACH OF THE THREE ALTERNATIVES AS COMPARED TO CONVENTIONAL RATE BASE TREATMENT FOR GENERATING PLANT ADDITIONS?

A. Yes. Each of the three alternatives moderates the current rate increase gradually (rather than abruptly increasing rates), better matches rate levels to the benefits of the output, promotes intergenerational equity, and provides improved economic efficiency as compared to "conventional" rate base treatment.

Q. IN WHAT WAY ARE RATE LEVELS BETTER MATCHED WITH THE BENEFITS OF OUTPUT THAN OCCURS UNDER TRADITIONAL RATEMAKING PRACTICES?

A. Under traditional ratemaking practice, cost recovery for a new generating plant is front-end loaded with respect to the plant's useful life. In contrast, benefits tend to be relatively greater in the later years because demand growth over time increases the value of generation increments and escalation of alternative energy costs increases the comparative worth of electric power. Under the alternative cost recovery approaches that I am presenting, charges to ratepayers should more closely correspond to the time distribution of ratepayer benefits.

Q. DO THESE RATEMAKING ALTERNATIVES REQUIRE OR DEPEND UPON A FINDING OF EXCESS CAPACITY?

A. No. Each of the three alternatives can be fully justified on rate moderation, intergenerational equity and economic efficiency grounds as compared to "conventional" ratemaking treatment without regard to excess capacity considerations. Each technique can be designed to assure that the utility investors are "made whole" through full cost recovery over the life of the plant, if that is the objective of the Commission.

Q. UNDER WHAT GENERAL CIRCUMSTANCES COULD ALTERNATIVE RATEMAKING TREATMENTS SUCH AS PHASE-IN AND DEFERRAL, SINKING FUND DEPRECIATION AND TRENDED RATE BASE BE JUSTIFIED?

A. Alternative ratemaking plans can be justified in order to moderate the severe rate increases frequently associated with major baseload plant additions. Conventional rate base treatment may result in economic disruption and dislocation within a utility's service area. Abrupt rate increases can result in substantial curtailment of energy use through short-term elasticity responses, alternative fuel switching, and shut-downs of key industrial and business customers.

Furthermore, the use of such methods may be warranted where they serve to better match ratepayer benefits and cost recovery over time. For example, if it is determined that a utility has constructed capacity in advance of actual system needs, the deferral of some part of the cost recovery for such capacity to future operating periods can be justified on traditional intergenerational equity grounds. Under the trended rate base or phase-in methods, initial period costs could be capitalized and deferred (much like AFUDC) to later periods when the capacity is expected to provide greater net system benefits.

Finally, alternative ratemaking approaches can be justified on the basis of improved cost signals and improved economic efficiency, which better reflect market realities and price trends through the private economy. If the rates charged for an existing plant's output decline over time due to the effects of traditional ratemaking, when the cost of producing electric power from new power plants is higher than rates presently charged, customers may make economically inefficient decisions to increase consumption because of the false price signal that electricity is getting "cheaper". Utilities, in turn, may interpret the

increase in customer demand to be a long term phenomenon, only to find that demand growth disappears when new plants are finally put on line to meet it. For example, when higher cost generating plants went into service and rates increased in the late 1970's, many electric utilities failed to achieve the demand growth forecasts that were the basis for constructing the new facilities. The front loading and subsequent decline of revenue requirements associated with traditional ratemaking may partially account for the cycle of apparent rapid demand growth followed by demand stagnation and excess capacity that has been experienced by many utilities over the past fifteen or so years. Thus, to the extent that alternatives to the traditional capital cost recovery method avoid front loading of revenue requirements and stabilize rates over a plant's life, the tendency for misallocations of resources will be reduced.

Q. WOULD THE GRADUAL PHASE-IN OF CAPACITY COSTS BE WARRANTED FOR A REGULATED UTILITY UNDER TRADITIONAL FAIR RATE OF RETURN CONSIDERATIONS?

A. Yes. The balancing of the interests of ratepayers and investors is a central issue in the ratemaking process.

A clear statement of the need to consider the interests of customers, as well as those of investors, appears in the Permian Basin Area Rate Cases, where the U. S. Supreme Court stated:

> . . . The Court in Hope found appropriate criteria by inquiring whether "the return to the equity owner [is] commensurate with returns on investments in other enterprises having corresponding risks" and whether the return was "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital" . . . These criteria, suitably modified to reflect the special circumstances of area regulation, remain pertinent, but they scarcely exhaust the relevant considerations.
>
> The Commission [Federal Power Commission] cannot confine its inquiries either to the computation of costs of service or to conjectures about the prospective responses of the capital market; it is instead obliged at each step of its regulatory process to assess the requirements of the broad public interests entrusted to its protection by Congress. Accordingly, the "end result" of the Commission's orders must be measured as much by the success with which they protect those interests as by the effectiveness with which they "maintain credit . . . and . . . attract capital. . ." (Emphasis added.)

Q. IS IT IMPORTANT TO BALANCE THE NEEDS OF BOTH CUSTOMERS AND STOCKHOLDERS IN DESIGNING AN APPROPRIATE RATEMAKING TREATMENT FOR THE COSTS OF MAJOR PLANT ADDITIONS?

A. Yes. Capital attraction is an important element in providing for adequate service. The decision to adopt any one particular ratemaking method should, therefore, be based on two fundamental objectives. First of all, the phase-in proposal should serve to: (a) effectively dampen the rate impacts associated with the addition of new plants to the system in their initial years; (b) provide a better match of loads and resources as well as costs and benefits over time; and, (c) promote economic efficiency. Second, the ratemaking approach selected should also produce financial results for the company sufficient to sustain its operations and provide for essential service growth. When these two interests are achieved, ratepayer and stockholder interests will be balanced so as to provide for the continuation of adequate utility service. As discussed in more detail below, each of the alternatives presented here could be implemented in a manner that simultaneously achieves both of these general objectives.

VI. Financial Accounting Issues

Q. HAS THE FINANCIAL ACCOUNTING STANDARDS BOARD (FASB) RECENTLY ISSUED AN EXPOSURE DRAFT OF A PROPOSED STATEMENT OF FINANCIAL ACCOUNTING STANDARDS WHICH WOULD AMEND FASB STATEMENT NO. 71 AND COULD AFFECT THE FINANCIAL ACCOUNTING OF A PHASE-IN PLAN ADOPTED IN THIS CASE?

A. Yes. The FASB issued an Exposure Draft which is entitled "Regulated Enterprises - Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs" on December 19, 1985. The Exposure Draft sets forth the FASB's proposed Statement of amendment to existing Statement No. 71, which provides accounting standards for reflecting the decisions of regulatory bodies for financial reporting purposes. While an Exposure Draft does not have the same authority as a final Statement, publication of an Exposure Draft occurs at the end of the development of new accounting standards. The Exposure Draft serves as a vehicle for public comment before the final Standard is issued. A public hearing will be held in June, 1986 for individuals and organizations to express their views about the standards proposed in the Exposure Draft. A copy of the Exposure

Draft is included as Exhibit__(J.W.-9). The proposed statement would be effective for fiscal years beginning after December 15, 1986, but would also apply to (a) all existing phase-in plans, (b) costs of abandoned plants for which rate orders have already been received, and (c) previously disallowed plant costs.

Q. IF THE FASB PROPOSAL IS ADOPTED, WILL THAT CONTROL THE REGULATORY ACCOUNTING THAT PECO MUST FOLLOW?

A. No. Regulatory accounting rules are determined by public utility regulatory authorities such as this Commission. If the proposed FASB amendment to Statement No. 71 is adopted, that will control the Company's accounting for financial reporting purposes.

Prior to the proposed amendment of FASB Statement 71, most regulatory accounting prescriptions would have been recognized in the Company's financial statements for financial reporting purposes. In fact, the purpose of the Statement, which relates only to regulated enterprises, is to recognize in the financial statements the economic effects of the ratemaking process. With this amendment to FASB Statement 71, amounts included in accounts for ratemaking purposes may differ

substantially from the amounts reported for financial purposes.

Q. WHAT EFFECT WOULD THE PROPOSED STATEMENT HAVE ON PECO'S FINANCIAL ACCOUNTING IF A PHASE-IN PLAN FOR LIMERICK 1 IS ADOPTED BY THIS COMMISSION?

A. The Exposure Draft requires that any phase-in plan meet three criteria in order for deferred revenues to be capitalized as a separate asset:

(1) The costs must be deferred under a formal plan that has been agreed to by the regulator;

(2) The plan must specify the timing of recovery of all costs deferred under the plan; and

(3) All costs deferred under the plan must be scheduled for recovery within 10 years of the date when the deferrals begin.

If a phase-in plan which does not meet any one of the three criteria is adopted, the proposed standards (if adopted by the FASB) would preclude PECO from capitalizing <u>any</u> deferred revenues during the deferral period for financial accounting purposes. The effect on PECO would be a reported decline in earnings in each

year of the deferral period equal to the amount of any deferred revenues. During the recovery period reported earnings would increase above a normal level since the collection of revenues deferred by the Commission in prior periods would appear in PECO's financial statements as current earnings.

Q. WHAT EFFECT WOULD THE ABSENCE OF A RETURN ON THE DEFERRED CHARGES HAVE ON PECO'S FINANCIAL ACCOUNTING IF THE PROPOSED STANDARD IS ADOPTED?

A. PECO's phase-in plan, which proposes no return on the balance of previously deferred amounts, would be accounted for just as if the Commission had disallowed a return on these amounts.

According to the rules contained in the Exposure Draft, if a return on the deferred asset balance is not allowed, the Company must recognize as a loss the present value of the disallowed return amounts. For financial accounting purposes, the recorded cost of the plant would be reduced by the present value of the future disallowed returns and a corresponding loss would be reported in the income statement. During the future period that no return is allowed on the cost deferrals,

the depreciation charges that would otherwise be recognized for the plant would be reduced by the present value of the amount of the disallowed return in each period. The effect on PECO's financial statements would be a decline in earnings only in the year that the loss is recognized. In all other years, because the depreciation charge would be reduced, there would be no apparent decline in earnings even though no return is earned on the deferred revenue balance.

Q. HAVE YOU DETERMINED THE AMOUNT OF THE LOSS THAT PECO WOULD BE REQUIRED TO RECOGNIZE UNDER THE PROPOSED STANDARDS IF PECO'S OWN PHASE-IN PLAN IS ADOPTED BY THE COMMISSION?

A. Yes. Under PECO's own proposal in this case, the amount of the write-off in 1986 would be $85.3 million if the Company's full rate request is granted, and assuming a discount rate equal to the overall cost of capital rate requested by PECO in this case. This write-off is not recognized in PECO's filing which was made prior to the FASB's issuance of its proposed statement.

Q. WHAT EFFECT WOULD THE PHASE-IN AND DEFERRAL OPTIONS THAT YOU ARE PRESENTING HAVE ON PECO'S FINANCIAL ACCOUNTING?

A. The two phase-in and deferral plans which I am presenting were designed to meet the three criteria for phase-in expressed in the proposed FASB amendment to Statement 71. All deferrals in each plan would be recovered within the ten-year maximum period and the timing of the recovery is specified. Of course, the proposed FASB Statement requires that the Commission also make clear in its order that the plan adopted is a formal plan for the recovery of the deferred charges within the ten-year limitation. Since all of the criteria would be met by these phase-in and deferral plans described in my testimony, PECO would be allowed to capitalize the deferred revenues as an asset for financial accounting.

Q. IF, IN ADDITION TO A PHASE-IN, THE COMMISSION DETERMINED THAT SOME COST OR RATE BASE DISALLOWANCE SHOULD BE IMPLEMENTED WITH RESPECT TO LIMERICK 1, COULD SUCH A WRITE-OFF BE ORDERED IN ADDITION TO A PHASE-IN?

A. Yes; that is a separate matter and is discussed later in my testimony.

Q. DOES THE SINKING FUND DEPRECIATION METHOD THAT YOU PRESENT REQUIRE ANY SPECIAL ACCOUNTING UNDER THE PROPOSED AMENDMENT TO FASB STATEMENT 71?

A. No. The sinking fund depreciation method, when used alone, does not involve the deferral of revenues to a future period. Therefore, PECO's financial accounting would not be affected by the proposed standard if the Commission chooses to adopt this depreciation method.

Q. DOES THE TRENDED RATE BASE METHOD THAT YOU PRESENT MEET THE FASB CRITERIA FOR A PHASE-IN PLAN?

A. No. The trended rate base method does not meet the criteria of the proposed statement because the deferred revenues are not recovered within ten years of the first deferral. In this case, if the proposed standard were adopted by the FASB, deferred revenues could not be capitalized by PECO for financial accounting purposes. However, PECO could keep what might be called "off-book" entries to track the deferral and subsequent recovery of revenues under the trended rate base

method. Adjustments could then be made to rate base and expenses for rate case purposes so that PECO would recover the deferrals in the proper periods.

VII. Phase-in and Deferral Method

Q. PLEASE DEFINE "PHASE-IN" AS THAT CONCEPT IS GENERALLY EMPLOYED.

A. In general, phase-in refers to spreading the impact of a significant increase in revenue requirements over a number of years rather than all at once. The intended effect of phasing-in an increased revenue requirement is to defer the immediate impact of rate increases.

The level of earnings need not be significantly affected by a phase-in procedure if there are provisions for the capitalization of deferred revenues, as is typically the case, for example, under AFUDC accounting practices. As a result, the adoption of a phase-in alternative can be structured to meet the traditional ratemaking criterion that the allowed return be equal to the cost of capital. Again, the use of these alternative ratemaking procedures does not require a determination of excess capacity or a disallowance of

costs. A phase-in could, however, accommodate such a disallowance.

Q. IS THE PHASE-IN PLAN PROPOSED BY PECO A PHASE-IN AND DEFERRAL PLAN AS YOU USE THE TERM?

A. Yes. The PECO phase-in proposal is that the revenue requirement be phased in over a three year period and that a deferral of the uncollected revenues be recorded. In years four, five and six, the cumulative deferred amount would be recovered as the result of a rate increase in year four.

Most phase-in and deferral plans, like the one proposed by PECO, gradually increase rates to a target level through the accumulation of rate increases. PECO's phase-in, which is based upon three annual increases of $223.6 million, accumulates base rates to the full $670.7 million requested level by the third year of the plan. An additional rate increase of $223.6 million as of the fourth year and in effect for each of the following two years, is the means of recovering the deferrals during the initial three year phase-in period. The effect, however, is to accumulate base rates to a level of $894.4 million by the end of the

sixth year. This is the result of a cumulative $670.7 level by the end of the third year plus an increase of $223.6 in year four. The accumulation of base rate revenues to levels in excess of required revenues is a characteristic of most phase-in plans. Once the phase-in and deferral recovery periods are completed, a rate decrease is necessary to bring rates down to their appropriate level. In the case of the PECO phase-in plan, the $223.6 million rate reduction due at the beginning of year seven occurs automatically by the elimination of the phase-in rider.

Q. WOULD THE PHASE-IN PLAN PROPOSED BY PECO RECOVER THE APPROPRIATE AMOUNT OF INCOME DEFERRED DURING THE PHASE-IN PERIOD?

A. No. The primary determinant of the $670.7 million rate increase requested by PECO is the $800 million-plus revenue requirement associated with bringing Limerick into service. As shown on Exhibit__(J.W.-8), however, the Limerick 1 revenue requirement declines each year, as a result of increases in the accumulated depreciation and deferred tax offsets to rate base.

PECO's plan is designed to recover, either in current rates or on a deferred basis, the full $670.7 million every year for six years. This same assumption is made implicitly under conventional ratemaking practice, when rate increases are authorized and left in place until a utility's next rate case.

When a rate increase resulting from a large plant addition is authorized, there is no concurrent rate-making device that reflects the annual decline in revenue requirements associated with a single plant flowing from the passage of time, although, as shown on Exhibit___(J.W.-8),, the annual reductions in revenue requirements are substantial for facilities the size of Limerick. To the contrary, traditional regulatory approaches pass the revenue requirement decreases through to utility shareholders, where the excess rates serve as an offset to regulatory lag when inflation is high.

Because the revenue requirements associated with Limerick 1 are substantial during the early years of its life, the amount of excess recovery under PECO's plan also will be substantial. On Exhibit__(J.W.-11), I have shown how this occurs. The revenue that PECO

foregoes during the phase-in period reduces income. But, because the income reduction is temporary (i.e., it will be recovered in years four, five and six), PECO will book deferred income as an exact offset to the income reduction. The plan assumes that Limerick 1 revenue requirements remain constant at their first year rate, and is designed to recover revenues under that assumption. But that assumption is not correct. Limerick 1 revenue requirements fall, and PECO recovers the amount of the decrease as excess return to its shareholders.

The plan details shown on Exhibit__(J.W.-11), which use the same Limerick 1 annual revenue requirements shown on Exhibit__(J.W.-8), illustrates the extent of the excess recovery. The balance of accumulated deferred income begins to fall in year 3, indicating that recovery has begun, although the PECO proposal is that recovery does not begin until year four. By the end of year six, when the PECO proposal considers recovery exactly complete, there has been a $275.1 million excess recovery. Moreover, if rates are reduced by only $223.6 million at the beginning of year seven, excess recovery will continue.

Q. PLEASE DESCRIBE THE PHASE-IN AND DEFERRAL METHODS WHICH YOU PROPOSE.

A. Phase-in and deferral methods involve deferring a portion of the revenue requirements claimed by PECO in this proceeding and then collecting these deferred revenues over time. I am presenting two phase-in and deferral plans for the Commission's consideration.

The first illustration of the phase-in and deferral approach provides for equal percentage increases for each year of the ten-year phase-in and recovery period. Application of the first phase-in plan begins by establishing the Company's annual total revenue level at existing rates. The base revenues of $2,502 million which were used for this calculation are the Company's proposed pro forma revenues at existing rates and test year markets. The allowed rate increase associated with the capital costs of Limerick 1 is limited to an equal annual percentage of the base revenues during a ten-year phase-in period. In this case, an annual 4.1 percent rate increase will phase the entire revenue requirement amount in over a five year period. The annual revenue requirement in excess of a 4.1 percent increase is deferred each year and recovery of the

deferrals takes place during the last five of the ten year period. The net of tax amount of the deferred revenues is the deferred income amount that investors will actually forego during the phase-in as compared to traditional ratemaking. This foregone amount is recovered in later periods. The deferral is booked as income net of tax, which reflects the fact that there is no current liability on the deferred revenues.

The next major feature of this phase-in plan is that a return is booked on the deferred amount. The deferred income balance is an asset (a deferred debit) which must be financed by permanent capital, just as plant in service is an asset financed by permanent capital. Recovery of the financing costs associated with the revenue deferral will be achieved (except for any disallowance found warranted) by recording a net of tax return (similar to AFUDC) during each year.

The calculation of revenue increases and deferrals for this ten-year phase-in and deferral plan is shown on Exhibit___(J.W.-12). Under this alternative, investors are made whole (i.e., there is no cost disallowance).

The second plan also incorporates a ten year phase-in and recovery period. In this case, rate increases are set at a constant dollar amount, rather than at a constant percentage amount over the period. This plan is similar to PECO's proposal, in that it phases-in the rate increase in equal installments. The constant dollar phase-in and deferral plan also includes booking and recovering a return on the deferred income balance. This aspect of the plan differs from PECO's approach, which includes no recovery of a return on the deferred balance. The revenue requirement for each of the ten years is shown as Exhibit__(J.W.-13).

Q. WOULD EACH OF THESE PHASE-IN AND DEFERRAL PLANS QUALIFY AS A PHASE-IN UNDER THE CRITERIA CONTAINED IN THE PROPOSED FASB AMENDMENT TO STATEMENT 71?

A. Yes.

Q. WOULD THE IMPLEMENTATION OF A PHASE-IN INCREASE THE RETURN ON COMMON EQUITY THAT INVESTORS REQUIRE ABOVE THE LEVEL OTHERWISE FOUND TO BE NECESSARY?

A. No. The only reason that such a ratemaking procedure would increase return requirements is if investors

associate it with an increase in risk. If perceived risk does not increase, return requirements will remain the same, all else equal. Phase-in plans for new plants are not atypical under today's regulatory standards. Many companies have voluntarily proposed phase-in plans to moderate the severe adverse impacts on consumers and the curtailment of usage which would result from "conventional" rate treatments. To the extent that a specific phase-in method is designed to make investors whole, capital costs should remain unaffected. Phase-in ratemaking techniques are surely already reflected in the capital markets and should be reflected in market based determinations of equity costs.

There have, of course, been many arguments relating risk and a delayed return in conjunction with AFUDC accounting. According to those arguments, deferred returns are more risky than cash returns because there is uncertainty as to whether or not they will be recovered. In fact, under some circumstances, it could be argued that a deferred revenue approach would reduce PECO's common equity risk. That would be the case, for example, if the rates which would provide for a full current cash recovery were so high that projected reve-

nues failed to materialize because consumers reduced the demand for electricity in response to increased rates. Moreover, the requirements imposed by the FASB 71 Amendment concerning the specification and certainty of recovery mean that deferrals under a phase-in plan are much less risky than AFUDC deferrals.

Also, as I previously indicated, a phase-in and deferred recovery mechanism is likely to provide increased cash flow (internal cash generation) during later periods when capital requirements for replacement or additional resources are necessary, thus reducing the risk of excessive debt accumulations or dilution of common stock values resulting from heavy external financing.

Q. WOULD AUTOMATIC REVENUE INCREASES BE NECESSARY UNDER A PHASE-IN AND DEFERRAL APPROACH?

A. In accordance with the proposed amendment to FASB Statement No. 71, a specific plan and schedule for the recovery of deferred revenues must be approved and implemented at the time that a phase-in is adopted in order to allow capitalization of deferred revenues. However, this does not mean that rates must be fixed

for the full phase-in and capital recovery period. Obviously, there may be other factors which may either increase or offset future rate adjustments associated with deferred revenue recoveries. Periodic adjustments in the allowed rate of return or other rate base and cost of service factors should continue to have regulatory consideration throughout the phase-in period.

FASB 71, if amended, requires that there be a definite plan for the recovery of deferrals. Rather than accommodating this requirement through automatic rate increases, such as a rider approach proposed by PECO, the better procedure would be to hear PECO's rate requests in the traditional manner, given the established phase-in schedule as one necessary element. If regular rate proceedings are held, the Commission will have the opportunity to make corresponding rate changes as new circumstances may warrant. Moreover, given the sensitivity of the revenue requirement to the allowed operation and maintenance expense, levels of sales growth, accumulated depreciation and deferred taxes, a regular examination of these issues is essential. At the same time, the Commission should specify the accounting procedures in advance so that each filing

will contain accurate information about the deferred revenue balance.

Q. WOULD YOU GIVE SOME EXAMPLES OF THE CHANGED CIRCUMSTANCES WHICH MAY REQUIRE MODIFICATIONS TO THE PHASE-IN AND RECOVERY PERIODS?

A. Yes. My phase-in and deferral exhibits under the percentage increase in revenue methods use the pro forma revenues at existing rates and test year market levels provided by the Company as the base revenues for calculating the annual percentage increase in rates. To the extent that retail sales grow, the rate increases necessary to phase-in the increase and to recover the deferred balance will be smaller than those contained in my schedules. It is, therefore, important that the base revenues established on an annual or periodic basis be pro-formed to reflect updated test year markets.

Another assumption I have made is a constant rate of return requirement over the entire period. Changes in the return (and also the Company's capital structure) may affect the rate increase stream. When the rate of return changes in a general rate case, the capitaliza-

tion rates used in the phase-in and recovery plans would change to correspond to those new capital cost circumstances, just as the return applied to all embedded rate base changes over time to reflect the Commission's allowed rate of return.

Q. WHAT VARIABLES AFFECT THE PHASE-IN REVENUE REQUIREMENT IN THIS CASE?

A. For purposes of the phase-in calculations included in my schedules, I have assumed the Company's requested rate of return, Limerick 1 plant costs,rate base, and depreciation expense. The actual phase-in revenue requirement granted, would, of course, be dependent upon the Commission's findings with respect to these variables.

VIII. Sinking Fund Depreciation Method

Q. PLEASE DESCRIBE THE EFFECT OF USING SINKING FUND DEPRECIATION RATES RATHER THAN CONVENTIONAL STRAIGHT LINE DEPRECIATION.

A. Straight line depreciation amortizes the cost of a plant in equal annual amounts over the life of the

plant. Under sinking fund depreciation, the depreciation expense is reduced below the straight line level in the early years of the plant's life, but escalates annually, so that the total cost of the plant is recovered over its useful life. The increase in depreciation expense each year is equal to the amount of decrease in the debt and equity return requirement resulting from the declining rate base. The result is that annual total capital costs (depreciation plus return on net investment) are equalized over the life of the plant, assuming no change in the rate of return. This contrasts with the decline of total capital costs from a higher initial level to near zero in the last year of the plant's life under straight line depreciation. In terms of "nominal" dollars, (i.e., without adjusting for inflation), the sinking fund approach eliminates the economically irrational decline in capital costs over the life of the plant.

Q. IS THE USE OF SINKING FUND DEPRECIATION ANALOGOUS TO THE MONTHLY PAYMENT SCHEDULES CONSUMERS FACE IN THE CASE OF A HOME MORTGAGE OR AUTOMOBILE LOAN?

A. Yes. A conventional home mortgage or automobile loan involves a flat monthly payment which consists of prin-

cipal and interest. The monthly payment is calculated in order to provide a repayment of the principal amount borrowed and the associated interest on the unpaid balance over the term or period of the loan. In the early years, the monthly payment consists primarily of interest payments while only a small amount goes toward repayment of the principal amount of the loan. The relative amounts of the interest and principal payments gradually reverse during the term of the loan. Toward the end of the loan period, the monthly payment constitutes primarily principal and very little interest. The increasing principal payments and sinking fund depreciation are analogous and serve as a return of the capital invested. The mortgage interest rate and the allowed return constitute the cost of capital or required return on the capital invested.

Q. IS THE SINKING FUND METHOD OF DEPRECIATION GENERALLY RECOGNIZED AS APPROPRIATE FOR REGULATED UTILITIES?

A. Yes. A number of recently constructed publicly owned thermal plants, such as WPPSS 2, Hatch, Vogtle, and Seattle City Light's share of Centralia, are being depreciated using the sinking fund method.

Q. PLEASE DESCRIBE THE ANNUAL REVENUE REQUIREMENT ASSOCIATED WITH LIMERICK 1 WHICH IS REFLECTED IN THE SINKING FUND DEPRECIATION CALCULATIONS ON EXHIBIT___(J.W.-14).

A. The first year revenue requirement for Limerick 1 under the sinking fund depreciation method is approximately $708.8 million, as compared to approximately $842.3 million under a conventional straight line depreciation approach. It should be noted that the sinking fund depreciation rates are dependent on the rate of return determined in this case. For purposes of my schedules, I have used the Company's requested rate of return.

On a total base rate increase basis, the first year revenue requirement would be the sum of the Limerick 1 increase and the other components (primarily the negative effect of fuel savings) of PECO's total $670.7 million request. This amount is $537.2 million.

IX. Levelized Real Cost Recovery or Trended Rate Base Method

Q. PLEASE EXPLAIN THE CONCEPT OF "LEVELIZED REAL CAPITAL COST RECOVERY" OR TRENDED RATE BASE.

A. The trended rate base concept was summarized by Sally Hunt of Consolidated Edison in her paper entitled "Trending the Rate Base" published in the May 13, 1982 issue of Public Utilities Fortnightly. The purpose is succinctly stated by Ms. Hunt:

> The point of trending would be to reduce prices in the early years, and let them rise over time, with positive effects on both intergenerational equity and economic efficiency. (p. 33, ibid.)

The concept was further refined and adapted to reflect tax effects and average rate base by the California PUC Staff in its report entitled "Ratemaking for San Onofre Nuclear Units #2 and #3: Economic, Financial, and Policy Analysis of Options," May 8, 1984.

Q. PLEASE DESCRIBE THE TRENDED RATE BASE METHOD.

A. Trended rate base encompasses two modifications to the traditional straight line depreciation method. First, it incorporates the sinking fund depreciation method as explained above. In addition, it splits the return on rate base into "real" and "inflation" components, and allows current recovery of the "real" return with the "inflation" component capitalized, included in rate

base, and amortized over the remaining life of the plant. The result is that the revenue requirement over the life of the plant increases at a rate that roughly corresponds to the experienced rate of inflation. This, of course, is similar to the revenue stream that would ordinarily be expected from a long-lived fixed asset in competitive markets.

Q. WHAT IS THE BASIS FOR ALLOWING CURRENT RECOVERY ONLY FOR THE "REAL" RATE OF RETURN?

A. The economic distortions resulting from traditional straight line depreciation tend to be amplified in times of inflation. That is so because debt and equity cost rates tend to vary with the expected inflation rate, thus compounding the "front loading" characteristic of straight line depreciation when inflation rate of return requirements are relatively high. When investors expect inflation, they demand a higher nominal return on their investment to compensate for the anticipated decline in the purchasing power of interest and dividend dollars they will receive in future years. It is generally recognized that current interest rates are substantially higher than they would otherwise be because of the "inflation premium" required to attract

capital. Thus, if the full rate of return is charged to ratepayers currently, today's ratepayers effectively pay for the anticipated decline in purchasing power that will occur in the future. A more equitable and economically rational approach would require today's ratepayers to pay the real cost of capital on the Company's investment, but would allocate the inflation component of the nominal return to future ratepayers who benefit from paying their rates with cheaper dollars. Under this approach, the real (inflation adjusted) cost of electricity will be brought more nearly into equilibrium over the life of the plant than under either the straight line or sinking fund methods.

Q. PLEASE EXPLAIN HOW THE REVENUE REQUIREMENT IS DETERMINED USING THE TRENDED RATE BASE METHOD.

A. Revenue requirements are determined in the conventional manner except for depreciation expense and return on rate base. Depreciation expense is determined using the sinking fund method as explained above.

The return on rate base is computed by first determining the Company's fair rate of return and capital structure. The weighted average (overall) rate of

return is then divided between real and inflation components. The inflation component is the estimated "inflation premium" that investors require to compensate for the effects of anticipated inflation. The "real" rate of return is simply the overall rate of return less the estimated inflation component.

The real rate of return is multiplied by rate base and included in current rates. The inflation component, however, is multiplied by rate base and capitalized. The capitalized return is included in rate base on a net of tax basis and is amortized to the cost of service over the remaining life of the plant, beginning in the year of capitalization. This approach assures the Company of a normal opportunity to recover the full amount of the cost of capital (both real and inflation premium) over the life of the plant, except to the extent that a disallowance is deemed appropriate by the Commission.

Q. HOW IS IT POSSIBLE TO DETERMINE THE EXPECTED INFLATION RATE EMBEDDED IN CURRENT CAPITAL COST RATES?

A. Expected inflation rates are not directly observable phenomena, but then neither are fair equity rates of

return or optimum capital structures. Such variables, however, can be rationally estimated by the Commission.

In a more fundamental respect, however, the precise determination of inflation premium components of capital cost rates is much less critical than the accuracy of estimating the cost of capital generally. To the extent that a commission errs in estimating the equity return, a utility will either under- or over-collect its costs. By contrast, deviations from optimal estimates of the inflation premium under the trended rate base method will merely shift current returns from one year to another, without affecting the total collection. For purposes of my computations here I have used 5 percent for long term inflation expectations.

Q. HAS ANY COMMISSION ADOPTED TRENDED RATE BASE AS A METHOD OF CAPITAL COST RECOVERY?

A. Yes. In Williams Pipe Line Company, Docket No. OR79-1-000, opinion issued June 28, 1985, the Federal Energy Regulatory Commission adopted a version of trended rate base similar in basic conception to the method that I have described.

Q. PLEASE DESCRIBE THE EFFECT ON REVENUE REQUIREMENTS USING THE TRENDED RATE BASE METHOD.

A. Exhibit___(J.W.-15) provides the estimated annual revenue requirement for the trended rate base method. The first year revenue requirement associated with Limerick 1 is approximately $437.0 million, assuming no disallowance. The first year base rate increase under this approach is $265.4 million.

Q. DOES THE TRENDED RATE BASE METHOD MEET THE REQUIREMENTS FOR A PHASE-IN FOR FINANCIAL ACCOUNTING PURPOSES UNDER THE PROPOSED AMENDMENT TO FASB STATEMENT 71?

A. No. As I stated earlier, because the deferral and recovery period is longer than ten years, no deferred revenues could be capitalized for financial accounting purposes. However, the Commission could use this method as long as the Company keeps separate accounts to track the deferral and recovery of revenues. The amendment to FASB Statement 71 does not require any write-off in the first year, but the deferred revenues would not be capitalized for financial reporting and net income in the financial statements would be lower than net income for ratemaking purposes in the early

years of the deferrals. In later years, the reported earnings would be higher than ratemaking return allowances since the financial reports will reflect deferred revenues as earnings in the year they are collected from ratepayers.

X. Financial Analysis of the Effects of Ratemaking Alternatives

Q. HAVE YOU ANALYZED THE EFFECTS OF PECO'S PHASE-IN PROPOSAL ON ITS FINANCIAL CONDITION?

A. Yes.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT PECO'S FINANCIAL CONDITION UNDER ITS PHASE-IN PROPOSAL?

A. Based upon the limited information about near-term future financial performance presented in PECO's financial forecast and provided in related data request responses, I have developed a series of financial ratios for the Company. These are shown on Exhibit___(J.W.-16).

Assuming that PECO's cash flow forecast is correct, and that PECO's own phase-in plan were adopted in this proceeding, the financial ratios indicate that PECO will be able to attract capital and maintain its credit. This conclusion is derived from a comparison of PECO's financial ratios to published standards associated with investment grade bonds ratings.

Q. PLEASE DESCRIBE EXHIBIT___(J.W.-16).

A. Exhibit___(J.W.-16) shows several ratios relating to cash flow, coverage and debt leverage. All of these ratios are calculated using the formulas published by Standard and Poor's as the "benchmark" ratios for rating electric utility bonds. The financial ratios were calculated from data presented in PECO's data request response DR-JFP11-City(12/20/85).

The two coverage ratios shown on the exhibit are pre-tax total interest coverage ratios, with and without AFUDC. The cash/capital ratio is the ratio of total cash flow (cash net income after all dividends, depreciation, deferred taxes and investment tax credits) to total permanent capital. The cash/construction ratio is total cash flow divided by cash construction expen-

ditures (i.e., excluding AFUDC). The debt leverage ratio is long-term debt dividend by total permanent capital.

Q. ARE THE 1986 RATIOS SHOWN ON EXHIBIT___(J.W.-16) COMPARABLE TO THOSE SHOWN ON TABLES 2 AND 4 ATTACHED TO COMPANY WITNESS PAQUETTE'S TESTIMONY (PECO STATEMENT NO. 3)?

A. No. Mr. Paquette's Table 2 shows similar ratios for 1986, assuming no rate increase. The 1986 ratios on Exhibit___(J.W.-16) include the assumption that rates are increased during 1986. Mr. Paquette's Table 4 shows ratios after a base rate increase of $682 million, but it appears that his 1986 calculations are for the year ended June 30, 1987, whereas the ratios shown on Exhibit___(J.W.-16) are full calendar years. Neither 1986 nor 1987 of the base data used in my calculation were as financially robust as the coverage ratios shown on Mr. Paquette's Table 4 suggest. Moreover, it appears that Mr.

Q. HAVE YOU COMPARED THE RATIOS SHOWN ON YOUR EXHIBITS TO THE NEW STANDARD & POOR'S BENCHMARKS, WHICH WERE PUBLISHED IN FEBRUARY OF 1985?

A. Yes. These new Standard & Poor's rating benchmarks are more stringent than those used in the past. For the A, BBB and BB bond rating categories, they are as follows:

	A	BBB	BB
Pre-Tax coverage, excluding AFUDC	2.5-4.0	1.5-3.0	less than 2.0
Cash/Capital	5.0-8.0	2.5-6.0	less than 3.0
Debt Ratio	44-52	50-58	more than 56

PECO's mortgage bonds are currently rated in the BBB category. Moreover, PECO's long-term mortgage debt (except for its premium bonds, whose yields reflect factors other than the market cost of long-term debt) trades at yields that are about the same as the S&P yield index for BBB bonds, indicating that investors view PECO's credit standing to be similar to that of other BBB-rated utilities.

Q. HOW DO THE RATIOS SHOWN ON EXHIBIT___(J.W.-15) COMPARE TO THE RATING BENCHMARKS PUBLISHED BY STANDARD AND POOR'S?

A. The ratios suggest that a bond rating of BBB is likely under PECO's phase-in proposal. This means that the PECO should be able to maintain its credit and continue

to provide utility service to ratepayers if PECO's phase-in proposal is accepted by the Commission.

Q. HAVE YOU PRESENTED SIMILAR FINANCIAL INDICATORS FOR THE ALTERNATIVE RATEMAKING APPROACHES DESCRIBED PREVIOUSLY IN YOUR TESTIMONY?

A. Yes. These ratios are shown on Exhibit___(J.W.-17). These ratios suggest that, under either of the phase-in and deferral plans, PECO could have difficulty maintaining a BBB bond rating in the near term future.

Q. YOU TESTIFIED PREVIOUSLY THAT THE BALANCING OF RATEPAYERS' AND INVESTORS' INTEREST WAS THE MOST IMPORTANT CONSIDERATION IN SELECTING A PHASE-IN PLAN. HAVE YOU DEVELOPED A PLAN WHICH BALANCES THOSE TWO COMPETING INTERESTS?

A. Yes, I have. This rate increase proposal, which is shown on Exhibit___(J.W.-18) consists of a phase-in and deferral plan in combination with the use of sinking fund depreciation.

This combination is beneficial to ratepayers because it eliminates some of the extreme front loading of

Limerick 1 costs. The combination plan also provides some cushion for rate increases at the time that Limerick 2 is expected to come into service. By phasing the required rate increase in over a ten year period, the initial rate stock attributable to Limerick 1 is reduced. The use of sinking fund depreciation also eliminates some of the front loading which occurs under traditional ratemaking practice. The first year rate increase under this plan would be $160 million.

The combination proposal also provides adequate protection to investors, as shown on Exhibit___(J.W.-19). The use of sinking fund depreciation contributes to this result. Moreover, the fact that a deferred return on the deferred income balance is permitted and that all deferrals are recovered over a ten year period means that the complications caused by the proposed amendment to FASB Statement 71 are avoided.

Q. HAVE YOU ALSO CONSIDERED THE FINANCIAL IMPACT OF THIS PHASE-IN PROPOSAL IN COMBINATION WITH YOUR PRIOR TESTIMONY CONCERNING PERFORMANCE STANDARDS FOR PECO?

A. Yes. This analysis is shown on Exhibit___(J.W.-20). Here I have shown the financial ratios under "best

case" and "worst case" assumptions. The best case would occur in the event that PECO is able to operate its plants efficiently and achieve high levels of performance. The worst case is that PECO will perform poorly.

The ratios shown in this comparison indicate that, in the event PECO is unable to meet reasonable plant performance standards, there somewhat greater difficulty in financing the construction of Limerick 2 than would be the case if PECO's performance were efficient. The consequence of the performance standards set forth in my prior testimony is that the burden of efficient operation is shifted from PECO's ratepayers to its shareholders.

Q. EARLIER IN YOUR TESTIMONY, YOU POINTED OUT THAT THE RATEMAKING ALTERNATIVES YOU HAVE DESCRIBED ARE NOT A SOLUTION TO A DETERMINATION THAT SOME OR ALL OF LIMERICK'S COSTS SHOULD BE DENIED RATE RECOVERY. IF THE COMMISSION DETERMINES THAT A DISALLOWANCE IS APPROPRIATE, WHAT WOULD BE THE EFFECT ON PECO'S ABILITY TO OBTAIN CAPITAL NECESSARY TO FULFILL ITS PUBLIC UTILITY OBLIGATION?

A. A disallowance would make it more difficult to finance the construction of Limerick 2. This is true whether there is a phase-in plan in effect for Limerick 1 or not. At the same time, my preliminary view is that PECO would be able to obtain financing, although perhaps on less than favorable terms.

PECO has suggested one way of combining a phase-in and disallowance, which essentially consists of postponing the phase-in into the second or third year of operation. Although there is no quantitative support for such a decision in PECO's filing, it may be deemed necessary to follow such a course if the goals of completing Limerick 2 and continuing to pay cash dividends to shareholders are given more emphasis than the pricing objectives and performance standards described set forth in my testimony.

In view of the apparent controversy in this case about the reasonableness of Limerick 1's cost of construction and the fact that there appears to be a potential for a disallowance, evaluation of the financial consequences of such a decision is appropriate. The issue is important and should be addressed with reference to the proposals to phase the cost Limerick 1 into rates.

The appropriate analysis is one that reflects PECO's probable future financial condition. Moreover, the analysis must relate the Commission's policies regarding the benefits and obligations of regulation to utilities and ratepayers to some factual set of consequences that could result from the selection of one policy over another. Yesterday I received forecast data from PECO in a form that could be used to develop such cause and effect relationships. Those data were the beginning point for the ratios presented in my testimony and exhibits, and they are also useful for evaluating the effects of a decision to disallow Limerick 1 costs.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-850152
	)	
Philadelphia Electric Company	)	

EXHIBITS

OF

DR. JOHN W. WILSON

January 1986

GEC Statement No. 1B

J. W. WILSON & ASSOCIATES, INC.
ECONOMIC COUNSEL
THIRD FLOOR • WATERGATE OFFICE BUILDING
2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

PHILADELPHIA ELECTRIC COMPANY

Income ($ millions)
Per Books

	12/31/84
Operating Revenue	2,981.0
Operating Expenses	2,073.1
Income Taxes Payable	120.6
Deferred Income Taxes 1/	126.1
Other Taxes	206.9
Operating Income	454.3
Other Income	251.1
Total Income	705.4
Interest Expense	213.0
Preferred Dividends	82.7
Earnings on Common Equity	409.7
Earnings/Common Equity	15.0%

1/ Includes state and federal net investment tax credits.

PHILADELPHIA ELECTRIC COMPANY

Annual Revenue Requirements Over
Plant Life Under Straight Line Depreciation
(Dollars in Millions)

Year	Book Depreciation	Return on Rate Base	Total Taxes	Revenue Requirement
1	101.61	455.09	268.72	842.27
2	101.61	428.44	257.17	803.28
3	101.61	404.45	247.11	768.55
4	101.61	381.80	234.39	732.45
5	101.61	359.15	221.66	696.35
6	101.61	337.17	211.02	663.06
7	101.61	315.85	199.04	629.08
8	101.61	294.53	187.06	595.11
9	101.61	273.22	175.08	561.13
10	101.61	257.90	181.90	552.46
11	101.61	248.60	176.67	537.63
12	101.61	239.29	171.44	522.80
13	101.61	229.98	166.21	507.96
14	101.61	220.68	160.98	493.13
15	101.61	211.37	155.75	478.30
16	101.61	202.06	150.52	463.46
17	101.61	192.76	145.29	448.63
18	101.61	183.45	140.06	433.80
19	101.61	174.14	134.83	418.96
20	101.61	164.84	129.60	404.13
21	101.61	155.53	124.37	389.30
22	101.61	146.22	119.14	374.46
23	101.61	136.91	113.91	359.63
24	101.61	127.61	108.68	344.80
25	101.61	118.30	103.45	329.96
26	101.61	108.99	98.22	315.13
27	101.61	99.69	92.99	300.29
28	101.61	90.38	87.76	285.46
29	101.61	81.07	82.53	270.63
30	101.61	71.77	77.30	255.79
31	101.61	62.46	72.07	240.96
32	101.61	53.15	66.84	226.13
33	101.61	43.85	61.61	211.29
34	101.61	34.54	56.38	196.46
35	101.61	25.23	51.15	181.63
36	101.61	15.92	45.92	166.79
37	101.61	6.62	40.69	151.96
38	11.37	0.16	4.23	16.07

NO. 011 | DECEMBER 19, 1985

Financial Accounting Series

EXPOSURE DRAFT

Proposed Statement of Financial Accounting Standards

Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

This Exposure Draft of a proposed Statement of Financial Accounting Standards is issued by the Board for public comment. Written comments should be addressed to:

Director of Research and Technical Activities
File Reference No. 011

Comment Deadline: April 30, 1986

Financial Accounting Standards Board
of the Financial Accounting Foundation

Proposed Statement of Financial Accounting Standards

Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

December 19, 1985

INTRODUCTION

1. FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*, was issued in December 1982. Shortly after the Statement was issued, major events in the electric utility industry caused the Board to review the effects of the Statement on the accounting for those events. After considering the application of the Statement, the Board decided to amend Statement 71 to provide more specific guidance for some of those events and to change the accounting for others.

2. This Statement amends Statement 71 to specify accounting for phase-in plans, plant abandonments, and disallowances of costs of newly completed plants.

STANDARDS OF FINANCIAL ACCOUNTING AND REPORTING

Accounting for Phase-in Plans

3. For purposes of this Statement, a *phase-in plan* is any plan that defers, for future recovery, either (a) a portion of the current operating costs[1] of a newly completed plant or (b) a portion of specified overall current operating costs of a regulated enterprise based on some measure related to a recently completed plant.[2]

---

[1]The term *current operating costs*, as used in this Statement, includes interest, an allowance for equity funds (that is, amounts provided for earnings on shareholders' investment), and a normal allocation of depreciation and decommissioning costs.

[2]For example, a phase-in plan might defer a percentage of a utility's overall cost of capital based on the percentage of the enterprise's total capacity that results from the newly completed plant.

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Proposed Statement of Financial Accounting Standards

Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

December 19, 1985

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4. All current operating costs that are deferred for future recovery by a regulator pursuant to a phase-in plan shall be capitalized as a separate asset (a deferred charge) if all of the following criteria are met. If any of those criteria is not met, none of the costs that are deferred for future recovery under the plan shall be capitalized for financial reporting purposes.

a. The costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.
b. The plan specifies the timing of recovery of all costs that will be deferred under the plan.
c. All costs deferred under the plan are scheduled for recovery within 10 years of the date when deferrals begin.

Any indirect disallowance of costs of the newly completed plant contained in the phase-in plan shall be recognized in accordance with paragraph 12 of this Statement.

Allowance for Funds Used during Construction

5. Paragraph 13 of Statement 71 requires an allowance for funds used during construction, including a designated cost of equity funds, to be capitalized in specified circumstances as part of the acquisition cost of the related asset. That cost shall be capitalized under those circumstances only if its subsequent inclusion in allowable costs for rate-making purposes is probable.[1]

Other Capitalization of an Allowance for Equity Funds

6. An allowance for equity funds shall be capitalized, as a deferred charge, when it is deferred by the regulator in conjunction with the short-term deferral of a cost increase. In order for the allowance for equity funds to qualify for capitalization under this paragraph, the deferral and capitalization must be ordered by the regulator, and both the related cost and the associated allowance for equity funds must be expected to be recovered either through an automatic rate adjustment clause or in the rates provided in the next rate case.

7. An allowance for equity funds is not an "incurred cost that would otherwise be charged to expense" as that phrase is used in paragraph 9 of Statement 71. Accordingly, such an allowance shall not be capitalized pursuant to paragraph 9 of Statement 71.

[1]The term *probable* is used in this Statement consistent with its use in FASB Statement No. 5, *Accounting for Contingencies*, to mean that a transaction or event is likely to occur.

Accounting for Abandonments

8. When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service, and the present value of the probable future revenues expected to be provided to recover the cost of that asset, if any, shall be reported as a separate asset (a deferred charge). Any excess of the carrying amount of the asset over that present value shall be recognized as a loss. The discount rate used to compute the present value shall be the overall rate of return allowed in the regulated enterprise's latest rate case in the jurisdiction in which recovery is expected to be received. In determining the present value, the enterprise shall consider such matters as (a) whether the regulator having jurisdiction has allowed recovery of and return on unrecovered investment in abandoned plants in the past, (b) the probable time period before such recovery is expected to begin, (c) the probable time period over which recovery will be provided, and (d) any probable disallowance of the cost of the abandoned asset. If the estimate of the probable recovery period is a range, the most likely period within that range shall be used to compute the present value. If no period within that range is more probable than any other, the present value shall be based on the minimum time period within that range. The recorded present value shall be adjusted from time to time as necessary if new information indicates that the amount to be recovered or the recovery period will be different from the estimates used to determine the present value. The amount of the adjustment shall be reported in the income statement as a loss or gain.

9. During the period between the date on which the present value of the probable future revenues expected to be provided is recognized and the date on which a rate order is received, the carrying amount shall be increased by accruing a carrying charge, using the rate that was used to compute the present value. Paragraph 26 and Schedule 2 of Appendix A illustrate that procedure.

10. When a rate order is received, the present value of the resulting future revenues shall be adjusted, if necessary, based on the recovery period specified in the rate order and the rate that was used for the calculation required by paragraph 8 above. The amount of the adjustment shall be reported in the income statement as a loss or gain.

11. Subsequent to the date of the rate order, the asset shall be amortized in a manner that will produce a constant return on the unamortized investment in the abandoned plant equal to the rate at which the probable revenues were discounted. Paragraph 28 and Schedule 3 of Appendix A illustrate that procedure.

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Disallowances of Costs of Newly Completed Plants

12. When it becomes probable that part of the cost of a newly completed plant will be disallowed for rate-making purposes, the part of the cost that is expected to be disallowed shall be deducted from the reported cost of the plant and charged to expense (recognized as a loss). If part of the cost is disallowed indirectly (for example, by disallowance of return on investment on a portion of the plant), an equivalent amount of cost shall be deducted from the reported cost of the plant and charged to expense (recognized as a loss).

Amendments to Existing Pronouncements

13. This Statement amends Statement 71 as follows:

a. Paragraph 13 is superseded by the following:

> Appendix B and FASB Statement No. XX (this Statement) illustrate the application of the general standards of accounting for the effects of regulation.

b. Footnote 6 to paragraph 9 is superseded by the following:

> [6]The term *probable* is used in this Statement consistent with its use in FASB Statement No. 5, *Accounting for Contingencies*. Statement 5 defines probable as an area within a range of the likelihood that a future event or events will occur. That range goes from probable to remote, as follows:
>
> *Probable*. The future event or events are likely to occur.
> *Reasonably possible*. The chance of the future event or events occurring is more than remote but less than likely.
> *Remote*. The chance of the future event or events occurring is slight.

c. The following footnote is added after the term *capitalize* in the second sentence of paragraph 9:

> [*]Phase-in plans shall be accounted for in accordance with paragraphs 3 and 4 of Statement XX (this Statement). An allowance for equity funds shall be capitalized only in the circumstances described in paragraph 15 of Statement 71 and in paragraphs 3-7 of Statement XX (this Statement). Costs of abandoned plants shall be accounted for in accordance with paragraphs 8-11 of Statement XX (this Statement).

d. The following footnote is added to the end of paragraph 10:

> [Disallowances of costs of newly completed plants, whether direct or indirect, shall be accounted for in accordance with paragraph 12 of Statement XX (this Statement).

Effective Date and Transition

14. The provisions of this Statement shall be effective for fiscal years beginning after December 15, 1986 and interim periods within those fiscal years. Earlier application is permitted. Retroactive application of this Statement in fiscal years for which financial statements have previously been issued is permitted, in which case the financial statements of all prior periods presented shall be restated. In addition, the financial statements shall, in the year this Statement is first applied, disclose the nature of any restatement and its effect on income before extraordinary items, net income, and related per share amounts for each period presented and on retained earnings at the beginning of the earliest period presented.

15. If financial statements for prior fiscal years are not restated, the effects of applying this Statement to existing situations shall be reported as the cumulative effect of a change in accounting principle, as described in APB Opinion No. 20, *Accounting Changes*, and the effect of adopting this Statement on income before extraordinary items, net income, and the related per share amounts shall be disclosed.

16. Initial application of this Statement will require the following adjustments to previously recorded assets with corresponding adjustments to reported net income of prior years or to the cumulative effect of an accounting change in the year of the change:

a. Existing phase-in plans shall be evaluated under the criteria of this Statement. If those existing plans do not meet the criteria of this Statement for capitalization of deferred costs, all costs deferred under those plans that have previously been capitalized shall be written off.
b. Amounts that were recorded in prior years for recoverable costs of abandoned plants shall be adjusted to the present value of the probable future revenues that are expected to be provided to recover the cost of those abandoned plants. The

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discount rate used to compute the present value shall be the overall rate of return allowed in the regulated enterprise's latest rate case preceding the date of the abandonment.

c. Disallowed plant costs of the kind covered in paragraph 12 shall be deducted from the reported cost of the related asset.

The provisions of this Statement need not be applied to immaterial items.

[Appendix A]

EXAMPLES OF APPLICATION OF THIS STATEMENT TO SPECIFIC SITUATIONS

17. This appendix provides guidance for application of this Statement to some specific situations. The guidance does not address all possible applications of this Statement. All the examples assume that the enterprise meets the criteria of paragraph 5 of Statement 71 for the application of Statement 71 by the enterprise. Cases like those illustrated in this appendix would probably involve income tax effects that could accrue to the utility in question. Some of those tax effects might be recognizable currently under APB Opinion No. 11, *Accounting for Income Taxes;* others might not be recognizable currently. The examples ignore those income tax effects because the amounts of those tax effects would be dependent on other taxable income.

18. Specific situations discussed in this appendix are:

	Paragraph Numbers
Accounting for a phase-in plan that includes an indirect disallowance	19–22
Accounting for abandonment	23–28
Accounting for a disallowance of plant cost	29–31
Accounting for a disallowance of plant cost resulting from a "cost cap"	32–34

Accounting for a Phase-in Plan That Includes an Indirect Disallowance

19. Utility A is an electric utility that operates solely in a single-state jurisdiction. On January 1, 19X1, Utility A's new electric generating plant becomes operational. The cost of that plant is $1 billion.

20. Utility A's regulator orders that the costs of the newly completed plant be phased in over a three-year period, as follows:

Year 1 A portion of the return on unrecovered investment is deferred by excluding 25 percent of the cost of the plant from the rate base.

Year 2 All of the remaining cost of the plant is to be included in the rate base with no recovery of previously deferred amounts.

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Year 3 All of the remaining cost of the plant is to be included in the rate base, plus additional revenue is to be provided equal to the cost of capital excluded from rates in year 1.

The order does not provide for recovery of a return on Utility A's investment in the deferred amounts. Utility A's weighted-average cost of capital in its latest rate case was 11 percent.

21. The phase-in plan is partially a disallowance of plant costs because no return on investment is provided for the deferred amounts. That disallowance would be recognized when it became probable. The amount of equivalent cost disallowed would be determined as shown in Schedule 1. The recorded cost of the plant would be reduced by that amount, and a corresponding loss would be reported.

22. The disallowance will reduce revenues only in years 1 through 3, so the depreciation charge that would otherwise be recognized for that plant in years 1 through 3 would be reduced by the amount of the effective disallowance attributable to those years (the amount in column 4 on Schedule 1). Amounts deferred under the plan (the amount for months 1-12 in column 1 on Schedule 1) would be capitalized as a separate asset, and that asset would be amortized as recovery occurs (in months 25-36), using the amounts in column 1 on Schedule 1.

Accounting for Abandonment

23. Utility B operates solely in a single-state jurisdiction that, in the past, has permitted recovery of amounts prudently invested in abandoned plants over an extended period of time without a return on unrecovered investment during the recovery period. Utility B decides to abandon a plant that has been under construction for some time. Although the possibility of abandoning the plant has been under consideration, abandonment was not considered probable before the actual decision was made. The recorded cost of the plant is $523 million; and the company estimates that it will incur additional contract cancellation penalties of approximately $22.5 million, which will be paid in approximately 6 months. Utility B's weighted-average cost of capital allowed in its latest rate case was 11.25 percent.

24. In view of the accumulated cost of the abandoned plant, Utility B believes that it is probable that recovery of cost without return on investment during the recovery period will be granted over a period that will be not less than 5 years nor more than 10 years, but it has no basis for estimating the exact time period within that range

Schedule 1

Utility A
Determination of Effective Disallowance
Return on Investment Disallowed for Amounts Deferred under Phase-in Plan

Month	(1) Cost Deferral (Recovery)	(2) Cumulative Amount Deferred	(3) R.O.I. on Cumulative Deferral	(4) Effective Disallowance
	(amounts in thousands)			
1	$ 2,292	$ 2,292	$ 21	$ 0
2	2,291	4,583	42	21
3	2,292	6,875	63	41
4	2,292	9,167	84	61
5	2,291	11,458	105	80
6	2,292	13,750	126	99
7	2,292	16,042	147	118
8	2,291	18,333	168	137
9	2,292	20,625	189	155
10	2,292	22,917	210	173
11	2,291	25,208	231	190
12	2,292	27,500	252	207
13	0	27,500	252	224
14	0	27,500	252	222
15	0	27,500	252	220
16	0	27,500	252	218
17	0	27,500	252	216
18	0	27,500	252	214
19	0	27,500	252	212
20	0	27,500	252	210
21	0	27,500	252	208
22	0	27,500	252	206
23	0	27,500	252	204
24	0	27,500	252	202
25	(2,292)	25,208	231	201
26	(2,291)	22,917	210	182
27	(2,292)	20,625	189	164
28	(2,292)	18,333	168	146
29	(2,291)	16,042	147	129

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Schedule 1
(continued)

Utility A
Determination of Effective Disallowance
Return on Investment Disallowed for Amounts Deferred under Phase-In Plan

Month	(1) Cost Deferral (Recovery)	(2) Cumulative Amount Deferred	(3) R.O.I. on Cumulative Deferral	(4) Effective Disallowance
	(amounts in thousands)			
30	(2,292)	13,750	126	117
31	(2,292)	11,458	105	95
32	(2,291)	9,167	84	78
33	(2,292)	6,875	63	62
34	(2,292)	4,583	42	46
35	(2,291)	2,292	21	31
36	(2,292)	0	0	15
Total loss to be recognized				$5,099

Computations:

Column (1) Cost of plant ($1 billion) × .25 × 11% ÷ 12
Column (2) Column (2) for prior month + Column (1) for current month
Column (3) Column (2) × 11% ÷ 12
Column (4) Present value (at beginning of month 1) at 11% of amount in Column (3) in prior month

that will be selected by the regulator. In view of the rate-making process in Utility B's jurisdiction, it will take approximately 18 months to obtain a rate order covering the abandoned plant.

25. When the abandonment becomes probable (in this case, at the date of the decision to abandon), Utility B would remove the plant from construction work-in-progress. It would record a new asset, a deferred charge representing the probable future revenues expected to result from the regulator's treatment of the cost of the abandoned plant, at the present value of the probable future revenues. In making that computation, the probable future revenues would be estimated at $9,091,667 per month for 5 years (based on an assumed straight-line recovery over the 5-year minimum period within the range), and those cash flows would be estimated to begin in 19 months. The computation of the amount to be recorded for the new asset and of the loss resulting from the abandonment would be:

Present value of $9,091,667 per month at 11.25% for 60 months, starting at the end of the 19th month (amount to be recorded as new asset)		$331,481,482
Cost of abandoned plant:		
Previously recorded cost	$523,000,000	
Cancellation charges to be accrued ($22,500,000 discounted at 11.25% for 6 months)	21,274,887	
Net cost		544,274,887
Loss to be recorded at time of abandonment		$192,793,405

26. Pending receipt of a rate order, Utility B would accrue carrying charges on the recorded asset at an 11.25 percent annual rate. Schedule 2 shows that computation. If it becomes probable that the period before rate action will be significantly longer or shorter than 18 months, the carrying amount of the new asset would be adjusted to reflect that new estimate.

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Schedule 2

Utility B

Accrual of Carrying Charges on Asset Resulting from Abandoned Plant

Month	Recorded Amount Beginning of Month	Carrying Charges Accrued	Recorded Amount End of Month
1	$ 351,481,482	$ 3,295,106	$ 354,776,588
2	354,776,588	3,326,031	358,102,619
3	358,102,619	3,357,212	361,459,831
4	361,459,831	3,388,686	364,848,517
5	364,848,517	3,420,455	368,268,972
6	368,268,972	3,452,521	371,721,493
7	371,721,493	3,484,889	375,206,382
8	375,206,382	3,517,560	378,723,942
9	378,723,942	3,550,537	382,274,479
10	382,274,479	3,583,823	385,858,302
11	385,858,302	3,617,422	389,475,724
12	389,475,724	3,651,335	393,127,059
13	393,127,059	3,685,566	396,812,625
14	396,812,625	3,720,118	400,532,743
15	400,532,743	3,754,995	404,287,738
16	404,287,738	3,790,197	408,077,935
17	408,077,935	3,825,731	411,903,666
18	411,903,666	3,861,597	415,765,263

27. Assume that the rate order is received at the end of the 18th month and specifies a recovery period of 6 years. Utility B would reflect that change in estimate by recognizing an additional loss, as follows:

Present value of $7,576,389 per month at 11.25% for 72 months (adjusted carrying amount of asset)	$395,378,451
Less: Carrying amount of asset (per Schedule 2)	415,765,263
Loss to be recorded at time of rate order	$ 20,386,812

The discount rate would not be adjusted to the rate permitted in that new rate order. That new rate reflects current conditions rather than the conditions that prevailed at the time of the abandonment.

28. As recovery occurs, the recorded asset would be amortized so as to reflect earnings on the unamortized asset at the 11.25 percent rate initially used to determine the present value of the asset. Schedule 3 shows the details of that computation.

Accounting for a Disallowance of Plant Cost

29. Utility C operates in two state jurisdictions. After an extensive "prudence investigation," the regulator in one of those state jurisdictions disallows $865 million of the $3.6 billion total cost of Utility C's newly completed nuclear generating plant. That state jurisdiction represents approximately 50 percent of Utility C's operations, and approximately 50 percent of the output of the newly completed plant is expected to be used in that state. The regulator in Utility C's other state jurisdiction has not participated in the "prudence investigation," and there is no indication that a similar disallowance is likely in that jurisdiction.

30. After consultation with counsel, Utility C decides that it should appeal the regulator's disallowance. Counsel indicates that there are valid bases for an appeal, but there is no way to predict the outcome of an appeal. What accounting should result?

31. Utility C should recognize the effective disallowance as a loss. The effective disallowance is 50 percent of the amount disallowed, or $432.5 million, because only 50 percent of the plant's cost will be recoverable from customers in that state. The disallowance should be recognized when it occurs. The possibility of a court overturning a regulator's decision on a question of fact represents a gain contingency of the type that is not recognized until it occurs.

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Schedule 3

Utility B

Computation of Amortization of Asset Resulting from Abandoned Plant

Month	(1) Unamortized Balance - Beg. of Month	(2) Return at 11.25%	(3) Revenues	(4) Amortization of Cost (Col 3 – Col 2)	(5) Unamortized Balance End of Month (Col 1 – Col 4)
19	395,378,451	3,706,673	7,576,389	3,869,716	391,508,735
20	391,508,735	3,670,394	7,576,389	3,905,995	387,602,740
21	387,602,740	3,633,776	7,576,389	3,942,613	383,660,127
22	383,660,127	3,596,814	7,576,389	3,979,575	379,680,551
23	379,680,551	3,559,505	7,576,389	4,016,884	375,663,688
24	375,663,688	3,521,847	7,576,389	4,054,542	371,609,126
25	371,609,126	3,483,836	7,576,389	4,092,553	367,516,572
26	367,516,572	3,445,468	7,576,389	4,130,921	363,385,651
27	363,385,651	3,406,740	7,576,389	4,169,649	359,216,003
28	359,216,003	3,367,650	7,576,389	4,208,739	355,007,264
29	355,007,264	3,328,193	7,576,389	4,248,196	350,759,068
30	350,759,068	3,288,366	7,576,389	4,288,023	346,471,045
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
80	78,836,757	739,095	7,576,389	6,837,294	71,999,463
81	71,999,463	674,995	7,576,389	6,901,394	65,098,069
82	65,098,069	610,294	7,576,389	6,966,095	58,131,974
83	58,131,974	544,987	7,576,389	7,031,402	51,100,572
84	51,100,572	479,068	7,576,389	7,097,321	44,003,251
85	44,003,251	412,530	7,576,389	7,163,859	36,839,393
86	36,839,393	345,369	7,576,389	7,231,020	29,608,373
87	29,608,373	277,578	7,576,389	7,298,810	22,309,562
88	22,309,562	209,152	7,576,389	7,367,237	14,942,326
89	14,942,326	140,083	7,576,389	7,436,306	7,506,020
90	7,506,020	70,369	7,576,389	7,506,020	0

Note: All computations assume that revenues for a month are received at the end of the month. At the end of each month, the unamortized balance of the asset is equal to the present value of the remaining revenues of $7,576,389 per month at an 11.25 percent annual interest rate.

Accounting for a Disallowance of Plant Cost Resulting from a "Cost Cap"

32. Utility D, which operates solely in one state jurisdiction, is constructing a new electric generating plant. The cost of the plant, which was originally expected to be $1.25 billion, is now expected to be approximately $3.5 billion. Various parties have charged that certain cost increases were a result of imprudent management of the construction.

33. To avoid the cost and time delay that would be involved in a full-scale "prudence investigation" of the construction of the plant, Utility D and its regulator agree that the total cost of the plant that will be allowable in determining depreciation and that will be allowed in Utility D's rate base will be $3.4 billion. What accounting is required as a result of that agreement?

34. Based on the agreement, $100 million of probable cost has been disallowed. Accordingly, Utility D would write off $100 million of the cost of the plant as a loss resulting from a disallowance at the date of the agreement (or at the date that the agreement becomes probable, if that date preceded the date of the agreement). Subsequently, if additional increases in the cost of the plant become probable and those costs are not allowable under the agreed maximum cost, those increases would also be recognized as losses from disallowances when they become probable.

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Appendix B

BACKGROUND INFORMATION

35. Statement 71 was issued in December 1982, effective for financial statements for fiscal years beginning after December 15, 1983. In early 1984, several different circumstances caused the Board to question whether the application of Statement 71 in practice was what the Board had intended.

36. Subsequent to issuing Statement 71, the Board became aware of several phase-in plans that involved capitalization of an allowance for equity funds on an operating plant. The Board considered issuing an Interpretation or permitting issuance of a Technical Bulletin to point out that capitalization of such an allowance was not permitted by Statement 71. However, after discussing the nature of phase-in plans and the reasons for their adoption with an affected company and its auditor, the Board decided to explore the use of phase-in plans in more depth before addressing the accounting for those plans.

37. During 1984, rate problems related to new nuclear electric generating plants of several utilities were widely discussed in the financial press. Comments credited to executives of those utilities indicated considerable question whether the utilities could bill rates based on the cost of those plants to their customers without losing a major part of their customer base. Some articles indicated that phase-in plans were likely for certain of those utilities, but they raised significant questions about the assurance of recovery of costs that would be deferred. Representatives of some regulatory commissions began to question the cost of certain of those new plants and to discuss possible major disallowances. Also, several plants in advanced stages of construction were abandoned. In a few states, courts ruled that utilities could not recover the costs of those abandoned plants from customers.

38. As a result of Board member concerns, the Board asked the staff to investigate whether guidance about the application of Statement 71 was needed in practice. The staff met several times with committees of Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners, and the Public Utilities Subcommittee of the American Institute of Certified Public Accountants (the AICPA Subcommittee). The Board also met with representatives of those groups and the Federal Energy Regulatory Commission.

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39. In November 1984, the Board received an AICPA Issues Paper, "Application of Concepts in FASB Statement of Financial Accounting Standards No. 71 to Emerging Issues in the Public Utility Industry." That paper listed 17 specific issues related to current problems in the electric utility industry identified by the the AICPA Subcommittee. The Board also received a comment letter from EEI on the issues raised in the AICPA Issues Paper.

40. In April 1985, the Board's Task Force on Regulated Enterprises met and discussed a staff draft of a possible Exposure Draft that encompassed most of the conclusions included in this Statement.

41. Subsequent to the April task force meeting, the Board received 31 letters from 39 affected enterprises and other interested parties commenting on the positions proposed in the staff draft discussed at the task force meeting and on the Board's tentative conclusions reached at its public meetings subsequent to that task force meeting.

Appendix C

BASIS FOR CONCLUSIONS

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Appendix C

BASIS FOR CONCLUSIONS

Introduction

42. This appendix summarizes considerations that were deemed significant by members of the Board in reaching the conclusions in this Statement. It includes reasons for accepting certain views and rejecting others. Individual Board members gave greater weight to some factors than to others.

General Considerations

43. Various letters received as the Board was developing the conclusions in this proposed Statement objected to the Board's conclusions about accounting for abandonments and disallowances of costs of newly completed plants on the basis that those decisions departed from the historical cost model of accounting for enterprises generally. The Board provided its view of the current accounting model in paragraphs 66-70 of FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*. Paragraph 66 acknowledges that the current model is not a pure "historical cost" model, as follows:

> Items currently reported in financial statements are measured by different attributes, depending on the nature of the item and the relevance and reliability of the attribute measured. The Board expects the use of different attributes to continue.

44. The Board also noted that the accounting specified by Statement 71 is itself a departure from the accounting framework applied by nonregulated enterprises generally. That Statement recognizes that rate actions of a regulator can have economic effects and requires certain items that would be charged to expense by nonregulated enterprises to be capitalized by regulated enterprises solely because the regulator's rate actions can provide reasonable assurance of future revenue. Both Statement 71 and this Statement extend the concept of cost capitalization to require, in certain circumstances, capitalization of an allowance for equity funds—an item that cannot be capitalized by a nonregulated enterprise.

45. The Board believes that a system that recognizes reasonable assurance of future revenues due to a regulator's actions as assets or as enhancements of assets must also recognize diminished prospects of future revenues due to a regulator's actions as

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reductions of assets. General purpose financial statements that recognized asset enhancements but not asset decrements would lack representational faithfulness—a critical qualitative characteristic if financial statements are to be reliable.

46. The Board believes that the accounting required by this Statement for abandonments and disallowed plant costs is consistent with other accounting that is required by Statement 71 and by this Statement. For example, the cost of equity funds is included in the allowance for funds used during construction (AFUDC) that Statement 71 requires to be capitalized by certain regulated enterprises but is excluded from the interest capitalized by nonregulated enterprises. That item is included for regulated enterprises solely because the regulator's allowance of AFUDC for rate-making purposes enhances the regulated enterprise's prospects of future revenues. Similarly, the act of the regulator in disallowing part of the cost of a newly completed plant or providing recovery of the cost of an abandoned plant without return on investment diminishes the enterprise's prospects of future revenues.

47. Some letters received in connection with this project objected to the proposals contained in this Exposure Draft on the basis that some regulators might use the resulting reported amounts to reduce rates from the levels that would otherwise be permitted. The Board is aware of the relationship between the rates set by regulators and costs and capital structures used for general purpose financial reporting. A regulator's treatment of costs or capital structures may affect the amounts reported in general purpose financial statements in a variety of ways, as specified in Statement 71 and in this Exposure Draft. Similarly, regulators may look to generally accepted accounting principles for treatment of specific costs. In still other cases, regulators might base rates on costs or capital structures unrelated to those reported in general purpose financial statements.

48. The Board is also aware that, if an accounting standard has indirect financial consequences that some view as onerous, like changing the amounts of current revenue allowed by regulators, the failure to act also has consequences that would be equally onerous to others. The Board cannot control or limit the uses of general purpose financial statements, but more importantly, the Board cannot allow its decisions to be tailored to assist the special interests of some affected enterprises or any other special interests.

Accounting for Phase-In Plans

49. Accounting for phase-in plans involves two separate issues under Statement 71. The first issue is whether, in view of the perceived need for a phase-in plan resulting from the size of the rate increase that would otherwise be required, it is reasonable to

assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers in the future. Paragraph 5(c) of Statement 71 requires that such an assumption be reasonable as a condition for application of that Statement.

50. Recently, some phase-in plans have been discussed in public forums as ways of retaining major customers. Utility officials have indicated that major industrial customers would leave their utility's service area or develop alternative sources of supply if rates were increased sufficiently to recover the costs of a newly completed plant. In that environment, a phase-in plan might be an indication that the utility cannot bill and collect rates that will recover its costs, rather than merely be an accommodation in the billing of revenues for the convenience of the utility's customers.

51. The other issue raised by a phase-in plan is whether it is appropriate to capitalize an allowance for equity funds after a plant begins operating. Paragraph 15 of Statement 71 requires capitalization of an allowance for equity funds as part of the acquisition cost of an asset *during construction*. Statement 71 does not provide for capitalization of an allowance for equity funds under any other circumstances. Most of the phase-in plans that have been ordered by regulators require deferral of an allowance for equity funds. That allowable cost is usually selected for deferral because the amount is large and it does not necessarily represent a current cash outlay.

52. The AICPA Issues Paper noted that, under Statement 71, a cost that would otherwise be charged to expense could be capitalized pursuant to a phase-in plan if recovery through future rates was probable, but an allowance for equity funds could not be capitalized other than during construction of a physical asset. The Issues Paper recommended that the regulator's selection of a specific allowable cost for deferral should not be important to accountants because any allowable cost can be selected with equal economic effect.

53. The Board believes that an allowance for equity funds is different from other costs for which recovery is provided by regulators. It is not an incurred cost. Rather, an allowance for equity funds is a computed amount of earnings to which equity shareholders are deemed to be entitled if their capital is prudently employed in providing utility services to customers. In an accounting context, that allowance is regarded as an unidentified portion of net income rather than as a cost. Thus, some believe that a regulator's deferral of an allowance for equity funds is a denial of current income and a later regulator's inclusion of that allowance in allowable cost of a future year is additional income earned in that future year. They view the current recognition of that future income, by capitalizing an allowance for equity funds, as rec-

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ogulion of income that is not yet earned. This view, in part, led to the Board's decision, in Statement 71, not to provide for capitalization of an allowance for equity funds except as part of the acquisition cost during construction of an asset. Capitalization of an allowance for equity funds used during construction of an asset was permitted, in part, because the result was considered similar to the result of capitalizing interest under FASB Statement No. 34, *Capitalization of Interest Cost*, as would be done by nonregulated enterprises. Upon reconsideration, the Board concluded that certain rate actions of a regulator provide sufficient assurance of the existence of earnings to justify capitalization of an allowance for equity funds in the limited circumstances described in this proposed Statement.

54. The AICPA Issues Paper recommended that only the probability of future recovery should be considered important in accounting for a phase-in plan. The Issues Paper suggested a list of factors that should be considered in determining whether recovery of amounts deferred under a phase-in plan is probable, but it indicated that none of the listed factors should be considered necessary or conclusive.

55. The Board concluded that, in view of management's involvement with regulators and other interested parties in negotiating the terms of a phase-in plan and management's commitment to the plan, that same management might tend to conclude that recovery of all amounts deferred under the plan is probable, regardless of the terms of the plan and the surrounding circumstances. Accordingly, the Board concluded that it should set specific, limiting criteria to be used in making that determination.

56. In deciding what criteria to select, the Board examined the phase-in plans that have been proposed and implemented to date. Those plans have tended to fit one of three different patterns, as follows:

a. Some plans provide for decreasing amounts to be deferred year by year for several years followed by increasing amounts of those deferrals to be recovered over several more years, with full recovery of all deferred amounts scheduled to be accomplished within a relatively short period.
b. Other plans provide for decreasing deferrals for several years with recovery of the deferred amounts to be provided over the life of the related plant.
c. Still other plans defer some amount of current costs without specifying either the extent of future deferrals or when recovery will be accomplished. Some of those plans base the deferral on "excess capacity," with the assumption that deferrals will continue as long as the "excess capacity" continues and recovery will occur over the life of the related plant thereafter.

57. *Recovery of deferred costs over a relatively short period.* The Board concluded that the first type of phase-in plan (subparagraph 56(a)) might provide adequate assurance of future revenues that will recover costs and a return on investment while avoiding extreme rate increases associated with the new plant. Accordingly, the criteria of this Statement will generally require the capitalization of current operating costs that are deferred for rate-making purposes under that type of plan. Paragraph 5(c) of Statement 71 requires, as a criterion for application, that it be reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers during the recovery period. This Statement includes a requirement that all amounts deferred under a phase-in plan be recovered within 10 years because the Board believes that adoption of a phase-in plan that requires a longer period to recover those deferred amounts necessarily creates an unacceptable degree of uncertainty as to whether that criterion for application of Statement 71 is met.

58. *Recovery of deferred costs over the life of the related plant.* The second type of phase-in plan (subparagraph 56(b)) results in a pattern of decreasing rates during the period in which previously deferred amounts are being recovered. Unlike construction costs, current operating costs are typically incurred with the expectation that they will be recovered currently. The Board believes that a phase-in plan warrants recognition, for general purpose financial reporting, only if it is limited to its stated purpose—avoiding extreme rate increases that would inconvenience customers while providing adequate assurance of future revenues that will recover costs and a return on investment. The Board concluded that a phase-in plan that will decrease rates during the period in which previously deferred costs are being recovered and extend that recovery period over a period from 30 to 40 years does not furnish sufficient assurance of recovery to warrant recognition.

59. Phase-in plans that provide recovery of deferred amounts over the life of the related plant would capitalize deferred amounts as additional plant cost. The Board noted that such deferred costs are not additional plant costs. Reporting those deferred amounts as though they are plant costs impairs users' ability to make future comparisons of the recorded cost of the related plant with costs of similar plants owned by other utilities.

60. *Recovery period for deferred costs not specified by the plan.* The Board concluded that the last type of phase-in plan (subparagraph 56(c)) does not warrant the accounting treatment provided in paragraph 4 in general purpose financial statements because the provisions of such a plan undermine the fundamental assumption that it is reasonable to assume that rates based on the enterprise's costs can be billed

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to and collected from customers. The Board believes that such a plan is not compatible with criterion 5(c) of Statement 71 because it provides no basis for concluding that recovery of deferred amounts is probable.

61. *No return on investment in deferred costs.* Some of the existing phase-in plans have deferred current operating costs for recovery in future periods and have not provided return on the investment in those deferred costs during the deferral period. The Board considered that type of phase-in plan and concluded that it is, in the environment that is subject to Statement 71, partially a deferral and partially a disallowance. The environment of individual cost-of-service regulation provides an enterprise an opportunity to earn a fair return on capital invested for the benefit of the enterprise's customers. In that environment, if costs are deferred solely to avoid the hardship to customers that would be caused by a significant increase in rates, the utility should be entitled to a return on the deferred amounts. If no return is provided, the regulator has indirectly disallowed part of the cost of the related plant and the accounting should reflect that disallowance.

Other Capitalization of an Allowance for Equity Funds

62. The Board also considered whether circumstances other than construction and phase-in plans might warrant capitalization of an allowance for equity funds. After considering a variety of circumstances, the Board concluded that capitalization is warranted in only one other type of situation.

63. In a rate case, regulators often identify specific changes in certain volatile costs for future recovery. For example, a regulator might conclude that the cost of fuel is sufficiently large and its price is sufficiently volatile that variations from the amount that is included in rates should be afforded recovery. In some cases, this is accomplished through an automatic adjustment clause that permits rates to be automatically adjusted to reflect variations in the cost of fuel used in prior periods. In other cases however, variations from the allowed cost of fuel are accumulated for action in the next rate case. Certain jurisdictions afford similar treatment to other costs. In those situations, the Board concluded that carrying costs on amounts invested in the accumulated deferred costs, including an allowance for equity funds, should be capitalized if recovery of those capitalized costs and a return on those deferred amounts over a relatively short period is probable.

Accounting for Abandonments

64. Historically, utilities usually have abandoned plants only in early stages of construction, rather than after major construction costs were incurred. Prior to Statement 71, regulated enterprises accounted for the costs of abandoned plants on a cost-recovery basis; that is, no loss was recorded so long as the regulator's allowance of revenues to recover those costs would recover the recorded costs. Statement 71 did not change that practice.

65. Recently, abandonments of plants under construction have become more common, and some utilities have abandoned plants during the later stages of construction. In many cases, the cost of abandoned plants is much greater than in the past; in a few cases, the utility's investment in those abandoned plants exceeds the total common shareholders' equity.

66. Regulators in many jurisdictions have provided recovery of the cost of abandoned plants without return on investment during the recovery period. That procedure has been described as a means of sharing the loss between customers and shareholders. A cost-recovery approach for accounting for abandonments was based on the view that the regulator was disallowing future earnings, rather than disallowing a portion of the cost of the abandoned plant. In reconsidering that issue in the context of today's environment, some Board members concluded that a cost-recovery approach, in effect, delays recognition of losses that are known to have been incurred. Although that approach might have little significance when applied to relatively immaterial items, the significance of the amounts involved in recent cases indicates that recognition of losses resulting from abandonments should not be delayed beyond the date when they are probable and reasonably estimable, or comparability of the financial statements will be impaired. Thus, the Board concluded that it should (a) emphasize the need for loss recognition as soon as a loss is probable and (b) require recognition of the disallowance of return on investment in abandoned assets when that disallowance becomes probable.

67. Other Board members believe that the probable future revenue that will result from inclusion of the cost of an abandoned plant in allowable costs for rate-making purposes is essentially a monetary asset. In their view, clearly the cost of an abandoned plant should be written off when abandonment is probable. The issue then is whether there is a basis for recognizing a different asset representing probable future revenues resulting from the regulator's action related to the abandonment. If it is probable that recovery of the cost of the abandoned plant will be provided for in future revenues, a new asset that is essentially a monetary asset should be recognized. That asset most closely resembles a long-term receivable that is usually recognized on

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the basis of its present value. They believe that a similar measurement basis is appropriate for probable future revenue that will result from a regulator's treatment of the cost of an abandoned plant.

68. The Board concluded that accruing a carrying charge on, or recognizing accretion of, the present value of the probable future revenue related to an abandonment is appropriate for two reasons. First, the basis used to record those assets recognizes the regulator's disallowance of future return on investment as a loss in the period in which it becomes probable. The disallowance that has been recognized should not affect the reported results of operations in later years, and accrual of a carrying charge has the effect of reporting income similar to what it would have been if there had been no disallowance. Second, the nature of the resulting asset is similar to a long-term receivable, even though Board members believe that it lacks some of the characteristics of a receivable. Accordingly, they concluded that the subsequent reporting should be consistent with that afforded a long-term receivable, and accrual of a carrying charge is consistent with accounting for a long-term receivable reported at its present value.

69. The Board considered adopting a requirement that all assets solely representing probable future revenue resulting from a regulator's actions be recorded at the present value of the future cash flows and decided not to adopt such a requirement at this time. Some Board members noted that the requirement of Statement 71 to recognize those other assets on a cost-recovery basis, which was a continuation of prior practice, does not appear to have caused major problems in practice. Other Board members noted that the rate treatment anticipated during construction, prior to abandonment of that construction, was full recovery of both cost and return on investment, whereas the cost of repairing storm damage, which is sometimes afforded recovery over a period of time without return on investment, represents a cash outlay usually made with the anticipation of that rate treatment. Thus, if the Board were to conclude that recording that asset at the amount of the consideration paid is not appropriate, that conclusion would be based on considerations somewhat different from those that the Board applied to abandonments.

Disallowances of Costs of Newly Completed Plants

70. Paragraph 10 of Statement 71 addresses disallowances by a regulator. That paragraph indicates that when a disallowance occurs, "the carrying amount of any related asset shall be reduced to the extent that the asset has been impaired. Whether the asset has been impaired shall be judged the same as for enterprises in general."

71. Recently, several disallowances of major amounts of cost on newly completed plants have been well publicized. The AICPA Issues Paper concludes that "the measure of whether an asset has been impaired [when part of the cost of that asset is disallowed for rate-making purposes] is whether net cash inflows (revenues less applicable expenses) are sufficient to cover the cost of the asset. In measuring expenses, interest applicable to the unit should be included, but equity return would not be included."

72. The Board concluded that the view described in the AICPA Issues Paper, which appears to approximate existing practice, is a narrower interpretation of an "impairment," as referred to in paragraph 10 of Statement 71, than is appropriate for the events in question. The Board believes that an impairment evaluation includes the estimation of losses in value that become determinable as a result of an identifiable event. For example, nonregulated enterprises that decide to discontinue an operation usually judge whether the assets of the operation that will be discontinued are impaired. That impairment evaluation usually is made by comparing the carrying amount of the assets to the present value of the amounts that are expected to be realized from the sale of those assets. An enterprise that suffers damage in a fire judges the resulting impairment by comparing the damage to the probable insurance proceeds. If the damage exceeds the insurance proceeds, an impairment is recognized by recording a loss even if the damaged property can continue to operate profitably in its damaged condition. The Board concluded that a regulator's disallowance of part of the cost of a newly completed plant creates an impairment that warrants recognition.

73. Some Board members also believe that the stated reason for certain recent disallowances of plant costs—that the costs were not productive or were not necessary for the completion of the plant—indicates that those costs should not be included in the carrying amount of the related plant. Nonregulated enterprises do not continue to carry identified nonproductive costs as part of the cost of their fixed assets, and regulated enterprises also should not do so.

74. The Board believes that the credibility of financial reporting in general would be diminished by the failure to recognize a diminution in value and a corresponding loss that is generally agreed to have occurred. When a regulator disallows a significant part of the cost of a newly completed plant, financial statements that do not report that disallowance as a loss reflect adversely on the representational faithfulness of those financial statements and of financial statements generally. Thus, the Board decided to amend Statement 71 to require loss recognition for such a disallowance.

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75. The Board considered making a more sweeping amendment of Statement 71, to require loss recognition for all cost disallowances by a regulator, whether related to a newly completed plant or otherwise. For example, regulators in some jurisdictions disallow costs of acquired companies in excess of the acquired company's book value and a variety of other types of costs. That approach was not taken because the Board concluded that the known problems in other areas do not warrant it.

Definition of Probable

76. The term *probable* was defined in Statement 71 differently from how it has been defined in other authoritative literature. The Board used a definition based on the definition used in FASB Concepts Statement No. 3, *Elements of Financial Statements of Business Enterprises*, because that definition was one of the criteria of an asset in Concepts Statement 3.

77. The AICPA Issues Paper questioned whether that definition was intended to be significantly different from the definition used in Statement 5 and indicated that the use of different definitions had caused some confusion in practice. The Board considered the concern expressed in the AICPA Issues Paper, and it decided to amend the definition in Statement 71 to a definition based on Statement 5.

78. The AICPA Issues Paper raised a number of other issues. After consideration, the Board decided that most of those issues were either judgment issues or involved unresolved legal questions; thus, the Board did not address those issues in this Statement.

Effective Date and Transition

79. The Board considered whether this Statement should be applied only to events occurring after the effective date or to all events of the types addressed. Applying this Statement only to events occurring after the effective date would diminish both comparability of the resulting financial statements among enterprises and consistency within an enterprise that had experienced such events both before and after the effective date. The types of events addressed by this Statement tend to have long-lasting effects on financial statements. For example, a decision whether to recognize a disallowance of plant cost as a loss affects reported depreciation and net income for the life of the related plant. Accordingly, the Board decided that this Statement should be applied to all phase-in plans, abandoned plants, and disallowed plant costs, regardless of whether those events occurred before or will occur after the effective date.

80. The Board also considered whether a longer time period between the date of issuance of this Statement and its effective date should be allowed, either for initial application of this Statement or for some or all existing phase-in plans, costs of abandoned plants for which rate orders have already been received, and disallowed plant costs.

81. Delayed application of accounting standards to existing situations is usually considered when either of two perceived problems is present. First, the change in accounting might change financial statement ratios that are the basis for restrictions under existing covenants. Those changes might restrict an affected enterprise's ability to pay dividends, issue new debt, and so forth. If required changes in the method of accounting for specific events or transactions result in accounting that is different from that contemplated when existing covenants were written, a delay period might be provided to allow affected enterprises sufficient time to obtain changes in those covenants.

82. Abandonments and disallowances have occurred in the past, and the past accounting for those events was well known. Accordingly, covenant restrictions that result from application of this Statement to abandonments and disallowances of plant costs might not have been intended by the parties to the covenant. Covenant restrictions that result from the accounting for phase-in plans required by this Statement are less likely to be unintended by the parties to the covenant. The need for such plans is unlikely to have been recognized when those covenants were adopted, and the parties are unlikely to have contemplated any specific accounting for those plans. Information available to the Board indicates that few enterprises that are likely to be affected by this proposed Statement would have existing covenant restrictions become effective as a result of the changes in accounting for abandonments and disallowances. In addition, it would appear generally that enterprises likely to be affected are not likely to be undertaking the actions that would be prohibited if the covenant restrictions were to become effective. That conclusion is based on disclosures of the nature of restrictive covenants in recent financial statements of companies that have been identified as having significant abandonments and disallowances.

83. The second reason for delayed application is that transactions might have been structured differently if the new rules had been known. Applied to a regulated environment, that argument usually would indicate that the rate order in question might have been different if the accounting required by this Statement had been required when the rate order was issued. That argument is unlikely to be valid for disallowances of return on investment in unrecovered cost of abandoned plants or disallowances of costs of newly completed plants. Those disallowances usually

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reflect a regulator's intent to cause the cost of an abandoned plant to be shared by stockholders rather than to fall entirely on customers, and to charge a disallowed plant cost to shareholders rather than to customers; thus, the accounting required by this Statement merely reflects the regulator's intent. On the other hand, based on negotiations on recent phase-in plans, it appears that the accounting requirements might well influence the terms of the rate order that implements a phase-in plan. The Board is uncertain whether it is reasonable to believe that existing plans might be changed to comply with the requirements of this Statement; but, if that is likely, the Board would consider allowing sufficient time for that to be accomplished.

84. The Board concluded that, based on available information, it should not delay application of this Statement to existing situations. However, enterprises that believe that such a delay is warranted by their specific situation are invited to describe, in their comments on this proposed Statement, their existing circumstances and explain why they believe that a delay would be beneficial.

Accounting for Income Taxes

85. If specified criteria are met, paragraph 18 of Statement 71 precludes regulated enterprises from recognizing deferred taxes on timing differences when taxes are treated as allowable costs on an "as paid" basis. During the course of its deliberations on its current project on accounting for income taxes, the Board considered how a new FASB Statement on accounting for income taxes should be applied to an enterprise with regulated operations reported in accordance with Statement 71. The Board expects this Exposure Draft to be read by most of the parties that will be affected by that issue, so it decided to explain its decision on applicability of the proposed Statement on income taxes, and the effects of that decision, in this document.

86. One of the general standards of accounting for the effects of regulation, in paragraph 12 of Statement 71, is that "actions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator." In its income tax project, the Board has tentatively concluded that deferred income taxes are a liability or asset. The Board's tentative conclusion on the income tax project, when viewed in the context of the Board's conclusion in paragraph 12 of Statement 71, indicates that regulated enterprises should be required to recognize the tax liability or asset that results from application of the proposed income tax Statement. Accordingly, the Board tentatively concluded that the proposed Statement on income taxes would delete paragraph 18 of Statement 71—the paragraph that prohibits regulated enterprises from recording deferred income taxes in certain cases.

87. Paragraph 9 of Statement 71 requires a regulated enterprise that applies Statement 71 to capitalize an incurred cost that would otherwise be charged to expense if the following criteria are met:

a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. [Footnote reference omitted.]
b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. . . .

Accordingly, if the income taxes that result from recording deferred tax liabilities in accordance with the proposed Statement on income taxes meet those criteria, the regulated enterprise would record those income taxes as an asset when the deferred tax liability is recorded. The resulting asset and liability would not be offset for general purpose financial reporting; rather, each would be displayed separately for a user's evaluation.

Alternative Views

88. One Board member believes that generally accepted accounting principles apply to rate-regulated enterprises and that, as long as there is a direct relationship between incurred costs and rate making, paragraph 9 of Statement 71 is consistent with those principles. He does not believe that any case can be made under either generally accepted accounting principles or paragraph 9 of Statement 71 for the recognition of an allowance for equity funds (that is, earnings on shareholders' investment) when revenues necessary to produce those earnings are deferred under a phase-in plan. That proposed accounting results in income being recognized before it is earned. That Board member believes (a) the reference in paragraph 9 of Statement 71 to "incurred costs" rather than "allowable costs" is essential in order for the accounting for rate-regulated enterprises to be in accordance with generally accepted accounting principles; and (b) paragraph 9 in Statement 71, together with the clarification of the meaning of "probable" contained in this proposed Statement, should be adequate to deal with phase-in plans for rate-regulated enterprises meeting the criteria of paragraph 5 of Statement 71. If the latter proves not to be the case, then that Board member would accept criteria similar to those in paragraph 4 of this proposed Statement for determining whether incurred current operating costs qualify for deferral.

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89. That Board member also believes the accounting in Statement 71 for the cost of abandoned plants and disallowed costs of operating plants are in accordance with the cost-recovery notion in generally accepted accounting principles, but acknowledges that a case can be made that the accounting proposed in this Statement for those two problems is also in accordance, or at least not in conflict, with generally accepted accounting principles. He believes, however, the case is not compelling, especially for (a) the accretion of the discount resulting from the fair valuing of the asset remaining after plant abandonments and (b) the write-off of disallowed costs of operating plants in all circumstances.

90. Another Board member does not support the accounting proposed in this Exposure Draft. Rather, he would reaffirm the existing provisions of Statement 71, including its conclusions that the "cost" of equity capital should not be capitalized after construction is completed and that only costs that would "otherwise be charged to expense" are candidates for capitalization as a result of rate actions. He does not see compelling reasons to consider major changes in Statement 71, which has been in effect for such a short time. He also sees no reason to modify the applicability of generally accepted accounting principles to regulated enterprises beyond those departures specifically called for by Statement 71.

91. That Board member disagrees with this proposed Statement primarily because it would extend required capitalization of the "cost" of equity capital both to operating plants, under phase-in plans, and to rate adjustment clauses and similar items. He is willing to accept the conclusion of Statement 71 that the equity component of an allowance for funds used during construction may be used as a surrogate for the additional interest that would be capitalized by enterprises in general. The concept of capitalizing carrying costs during construction, as an acquisition cost, is in accordance with generally accepted accounting principles. Extending capitalization beyond the construction period constitutes capitalization of a holding cost, which is not permitted for enterprises in general.

92. That Board member sees no reason to make an exception to this general prohibition against capitalizing holding costs in the case of regulated enterprises. In his view, such an exception would result in premature income recognition. Income related to imputed costs should be recognized when revenues are realized, not before.

93. That Board member also objects to the proposed requirement to value recoverable costs of abandoned plant at their present value. He would record the costs associated with abandoned plants at the lower of cost or gross recoverable amount. In his view, this cost-recovery approach, now specified by Statement 71, should not be

changed because it conforms with accounting for enterprises in general. Further, he believes that valuing recoverable costs on a present value basis results in inappropriate overstatements of income in subsequent periods.

94. Finally, that Board member objects to the proposed requirement to recognize disallowances of costs of newly completed operating plants as losses. In his view, a regulator's disallowance of part of the cost of a fixed asset is an event warranting disclosure but not accounting recognition. The asset should be carried at its acquisition cost provided this cost is not higher than the asset's gross recoverable amount. He believes that reflecting a disallowance as a loss, with a corresponding reduction of depreciable fixed assets, inappropriately overstates income of subsequent periods.

95. A third Board member disagrees with the conclusions of this proposed Statement on two counts. First, he believes that there is no justification for the recording of an asset for the allowance for equity funds after an asset has been acquired and is ready for its intended use. Second, he does not believe that impairment of a long-lived asset should be recorded based on the asset's discounted present value in the rate-regulated industries when similar impairments are generally recorded based on recoverable cost in other industries. In his opinion, both of those approaches result in making less profitable companies look the same as more profitable companies. By capitalizing deferrals under a phase-in plan, a company that is not receiving revenue to recover its current operating costs is made to appear as profitable as one that is. By recording revenues expected to result from abandonments at their discounted present value and by recording operating plants at the amount that will be allowed by the regulator, a company that is receiving revenues designed to provide recovery of less than full cost and return on investment is made to appear as profitable as a company that is receiving revenues equal to full cost and return on investment, once the loss required to achieve that answer is recognized. That Board member believes that making all companies appear to have the same return on investment should not be an objective of accounting.

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Summary Description of Ratemaking Alternatives Described in Testimony

I. Phase-in and Deferral Approach

- PECO's phase-in proposal
- Ten equal percentage rate increases
- Ten equal dollar rate increases

II. Sinking Fund Depreciation Approach

III. Trended Rate Base Approach

IV. Sinking Fund with Phase-in and Deferral

PHILADELPHIA ELECTRIC COMPANY

Phase-In Plan Proposed by PECO
(Dollars in Millions)

Year	Revenue Requirement	Revenue Increase	Cumulative Increase 1/	Deferred Income	Accumulated Deferred Income	Return on Deferral
1	$842.3	$395.1 1/	$395.1	$224.6	$224.6	$0.0
2	803.3	233.6	618.7	92.7	317.3	0.0
3	768.6	233.6	842.3	(37.0)	280.3	0.0
4	732.5	233.6	1,065.8	(167.5)	112.8	0.0
5	696.4	0.0	1,065.8	(185.6)	(72.8)	0.0
6	663.1	0.0	1,065.8	(202.3)	(275.1)	0.0
7	629.1	(223.6)	842.3			

1/ Before net base revenue decrease of $171.6 ($842.3 - $670.7).

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Equal Percentage Rate Increases
(Dollars in Millions)

Year	Revenue Requirement	Revenue Increase	Cumulative Increase 1/	Deferred Income	Accumulated Deferred Income	Return on Deferral
1	$842.3	$272.9 1/	$272.9	$286.0	$300.2	$14.2
2	803.3	106.2	379.1	213.1	553.8	40.5
3	768.6	110.5	489.6	140.0	756.1	62.2
4	732.5	115.0	604.5	64.2	898.9	78.5
5	696.4	119.6	724.2	(14.0)	973.8	88.9
6	663.1	124.5	848.6	(93.2)	972.9	92.4
7	629.1	129.5	978.1	(175.3)	885.8	88.2
8	595.1	134.7	1,112.9	(260.1)	701.0	75.3
9	561.1	140.2	1,253.1	(347.6)	406.0	52.5
10	552.5	145.9	1,399.0	(425.2)	0.0	19.3
11	537.6	(861.4)	537.6			

1/ Before net base revenue decrease of $171.6 ($842.3 - $670.7).

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Equal Dollar Rate Increases
(Dollars in Millions)

Year	Revenue Requirement	Revenue Increase	Cumulative Increase 1/	Deferred Income	Accumulated Deferred Income	Return on Deferral
1	$842.3	$285.5 1/	$285.5	$279.7	$293.6	$13.9
2	803.3	114.0	399.5	202.8	535.8	39.4
3	768.6	114.0	513.4	128.2	723.7	59.8
4	732.5	114.0	627.4	52.8	851.2	74.7
5	696.4	114.0	741.3	(22.6)	912.3	83.7
6	663.1	114.0	855.3	(96.6)	901.8	86.1
7	629.1	114.0	969.2	(170.9)	812.3	81.3
8	595.1	114.0	1,083.2	(245.2)	635.9	68.7
9	561.1	114.0	1,197.1	(319.5)	363.8	47.4
10	552.5	114.0	1,311.1	(381.1)	0.0	17.3
11	537.6	(773.5)	537.6			

1/ Before net base revenue decrease of $171.6 ($842.3 - $670.7).

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Annual Revenue Requirements Over
Plant Life Under Sinking Fund Depreciation
(Dollars in Millions)

Year	Book Depreciation	Return on Rate Base	Total Taxes	Revenue Requirement
1	5.74	459.78	229.53	708.78
2	6.47	441.86	223.21	684.81
3	7.29	426.54	218.39	665.11
4	8.22	412.48	210.89	644.07
5	9.26	398.33	203.39	623.05
6	10.44	384.74	197.98	604.88
7	11.76	371.70	191.24	586.06
8	13.25	358.54	184.49	567.28
9	14.94	345.23	177.75	548.54
10	16.83	337.77	189.81	555.17
11	18.97	336.13	189.82	555.69
12	21.38	334.28	189.83	556.27
13	24.10	332.20	189.85	556.93
14	27.15	329.85	189.86	557.67
15	30.60	327.21	189.88	558.51
16	34.49	324.22	189.90	559.45
17	38.87	320.87	189.92	560.51
18	43.80	317.08	189.94	561.71
19	49.37	312.81	189.97	563.06
20	55.63	308.00	190.00	564.58
21	62.70	302.58	190.04	566.29
22	70.66	296.48	190.07	568.22
23	79.63	289.59	190.12	570.40
24	89.74	281.84	190.17	572.85
25	101.14	273.10	190.22	575.61
26	113.98	263.24	190.29	578.73
27	128.46	252.14	190.36	582.24
28	144.77	239.63	190.44	586.19
29	163.15	225.53	190.53	590.65
30	183.87	209.63	190.63	595.67
31	207.22	191.72	190.74	601.33
32	233.53	171.54	190.87	607.71
33	263.18	148.79	191.02	614.90
34	296.60	123.16	191.18	623.01
35	334.26	94.27	191.36	632.14
36	376.71	61.71	191.57	642.43
37	424.54	25.01	191.81	654.03
38	50.72	0.36	21.49	74.01

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Annual Revenue Requirements Over
Plant Life Under Trended Rate Base
(Dollars in Millions)

Year	Book Depreciation	Cash Return on Rate Base	Total Taxes	Revenue Requirement	Cum. Def. Ret.
1	5.74	283.98	134.62	436.98	140.82
2	6.47	283.80	142.24	449.40	277.54
3	7.29	284.91	150.74	464.26	410.69
4	8.21	286.51	156.28	476.86	540.38
5	9.25	287.77	161.84	489.40	666.28
6	10.43	289.08	169.34	504.27	788.26
7	11.75	290.41	175.38	518.01	906.16
8	13.25	291.34	181.44	531.69	1019.61
9	14.93	291.83	187.51	545.30	1128.20
10	16.82	295.53	211.15	580.60	1233.31
11	18.96	302.55	221.65	606.47	1336.32
12	21.37	309.26	232.45	632.95	1436.70
13	24.08	315.60	243.55	660.04	1533.92
14	27.14	321.52	254.94	687.76	1627.36
15	30.58	326.94	266.63	716.09	1716.35
16	34.47	331.78	278.62	745.03	1800.16
17	38.84	335.97	290.91	774.59	1877.99
18	43.78	339.40	303.51	804.76	1948.98
19	49.33	341.98	316.42	835.54	2012.16
20	55.60	343.59	329.63	866.93	2066.49
21	62.66	344.10	343.15	898.91	2110.84
22	70.62	343.39	356.98	931.48	2143.96
23	79.58	341.28	371.11	964.65	2164.50
24	89.69	337.62	385.54	998.39	2170.98
25	101.08	332.22	400.26	1032.70	2161.80
26	113.91	324.88	415.27	1067.57	2135.21
27	128.38	315.36	430.56	1102.97	2089.30
28	144.68	303.42	446.11	1138.89	2022.02
29	163.05	288.79	461.90	1175.30	1931.13
30	183.75	271.16	477.90	1212.15	1814.22
31	207.08	250.21	494.06	1249.37	1668.71
32	233.38	225.58	510.31	1286.84	1491.83
33	263.01	196.86	526.54	1324.36	1280.69
34	296.41	163.64	542.53	1361.56	1032.34
35	334.05	125.48	557.85	1397.63	744.00
36	376.47	81.94	571.47	1430.56	413.69
37	424.27	32.74	579.53	1452.68	43.29
38	50.68	0.41	64.60	162.45	.00

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
PECO's Phase-In Proposal

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.3	2.6	2.7	3.0
Excluding AFUDC	1.3	2.0	2.3	2.7
Cash/Capital	3.2%	2.6%	3.7%	4.8%
Cash/Construction	49%	31%	51%	80%
Debt Leverage	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1986

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.3	2.4	2.4	2.6	2.3
Excluding AFUDC	1.3	1.3	1.4	1.9	1.6
Cash/Capital	3.2%	2.5%	2.5%	4.9%	3.4%
Cash/Construction	49%	38%	39%	74%	52%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1987

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.6	2.4	2.4	2.9	2.3
Excluding AFUDC	2.0	1.6	1.6	2.5	2.0
Cash/Capital	2.5%	.6%	.7%	4.6%	1.8%
Cash/Construction	31%	8%	10%	57%	23%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1988

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.7	2.4	2.4	2.8	2.3
Excluding AFUDC	2.3	1.7	1.7	2.4	1.9
Cash/Capital	3.7%	.6%	.8%	3.4%	1.0%
Cash/Construction	51%	8%	12%	46%	15%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1989

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	3.0	2.5	2.5	2.7	2.3
Excluding AFUDC	2.7	1.8	1.7	2.3	1.9
Cash/Capital	4.8%	1.2%	1.4%	2.6%	.6%
Cash/Construction	80%	23%	25%	44%	12%
Debt Leverage	50%	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Combination Phase-In and Deferral With Sinking Fund
(Dollars in Millions)

Year	Revenue Requirement	Revenue Increase	Cumulative Increase 1/	Deferred Income	Accumulated Deferred Income	Return on Deferral
1	$708.8	$331.6 1/	$331.6	$198.9	$198.9	$9.4
2	684.8	160.0	491.6	121.7	320.6	24.7
3	665.1	160.0	651.6	39.1	359.7	32.3
4	644.1	160.0	811.6	(52.5)	307.2	31.6
5	623.1	(22.9)	788.6	(56.7)	250.5	26.5
6	604.9	(22.9)	765.7	(59.8)	190.7	20.9
7	586.1	(22.9)	742.9	(63.6)	127.1	15.1
8	567.3	(22.9)	719.8	(67.8)	59.3	8.8
9	548.5	(70.0)	649.8	(48.5)	11.8	3.4
10	555.2	(70.0)	579.8	(11.9)	0.0	.6
11	555.7	(24.1)	555.7			

1/ Before net base revenue decrease of $171.6 ($824.3 - $670.7).

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
Combination Sinking Fund and Phase-In

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.4	2.5	2.6	2.7
Excluding AFUDC	1.5	1.9	2.1	2.2
Cash/Capital	2.8%	1.5%	2.0%	3.2%
Cash/Construction	43%	19%	28%	57%
Debt Leverage	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
PECO's Phase-In Proposal

	1986	1987	1988	1989
EFFICIENT OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.4	2.5	2.8	3.0
Excluding AFUDC	1.5	1.9	2.1	2.3
Cash/Capital	2.9%	1.6%	2.1%	3.3%
Cash/Construction	44%	21%	31%	60%
Debt Leverage	50%	50%	50%	50%
POOR OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.4	2.5	2.5	2.6
Excluding AFUDC	1.5	1.9	2.0	2.2
Cash/Capital	2.6%	1.0%	1.5%	2.6%
Cash/Construction	40%	14%	22%	47%
Debt Leverage	50%	50%	50%	50%

J.W. Wilson
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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
PECO's Phase-In Proposal

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.5	2.6	2.8	3.1
Excluding AFUDC	1.5	2.0	2.3	2.8
Cash/Capital	.8%	2.8%	4.2%	5.3%
Cash/Construction	12%	36%	59%	92%
Debt Leverage	50%	50%	50%	50%

PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1986

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.5	2.6	2.6	2.9	2.6
Excluding AFUDC	1.5	1.6	1.6	2.1	1.9
Cash/Capital	0.8%	0.1%	0.2%	2.4%	1.0%
Cash/Construction	12%	1%	3%	38%	16%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1987

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.6	2.4	2.4	2.9	2.4
Excluding AFUDC	2.0	1.6	1.6	2.6	2.0
Cash/Capital	2.8%	1.0%	1.1%	4.9%	2.2%
Cash/Construction	36%	13%	15%	62%	28%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1988

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	2.8	2.4	2.5	2.8	2.3
Excluding AFUDC	2.3	1.7	1.7	2.4	2.0
Cash/Capital	4.2%	1.1%	1.4%	3.9%	1.6%
Cash/Construction	59%	17%	20%	53%	23%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators: 1989

	PECO Proposal	Equal % Phase-in	Equal $ Phase-in	Sinking Fund	Trended Rate Base
Pre-Tax Coverage					
Including AFUDC	3.1	2.5	2.6	2.9	2.4
Excluding AFUDC	2.8	1.8	1.9	2.4	1.9
Cash/Capital	5.3%	1.8%	2.1%	3.2%	1.5%
Cash/Construction	92%	34%	39%	56%	26%
Debt Leverage	50%	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
Combination Sinking Fund and Phase-In

	1986	1987	1988	1989
Pre-tax Coverage				
Including AFUDC	2.7	2.6	2.7	2.9
Excluding AFUDC	1.7	1.9	2.1	2.4
Cash/Capital	.4%	1.8%	2.5%	3.9%
Cash/Construction	7%	24%	36%	70%
Debt Leverage	50%	50%	50%	50%

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PHILADELPHIA ELECTRIC COMPANY

Financial Indicators Reflecting
Combination Sinking Fund and Phase-In

	1986	1987	1988	1989
EFFICIENT OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.6	2.6	2.7	2.8
Excluding AFUDC	1.7	2.0	2.1	2.4
Cash/Capital	.5%	1.9%	2.7%	4.0%
Cash/Construction	8%	25%	39%	72%
Debt Leverage	50%	50%	50%	50%
POOR OPERATING PERFORMANCE				
Pre-tax Coverage				
Including AFUDC	2.6	2.5	2.6	2.8
Excluding AFUDC	1.7	1.9	2.0	2.3
Cash/Capital	.2%	1.4%	2.0%	3.3%
Cash/Construction	3%	19%	30%	60%
Debt Leverage	50%	50%	50%	50%

City Statement No. 1

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

DIRECT TESTIMONY

OF

ARIE P. SCHINNAR, Ph.D.

DOCKETED
FEB 24 1986

ECONOMIC IMPACT ANALYSIS OF

PROPOSED RATE INCREASE

FOLDER

January 1986

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Direct Testimony of Arie P. Schinnar

Q. Please state your name and business address for the record.

A. My name is Arie P. Schinnar. My business address is the Department of Public Policy and Management, The Wharton School, University of Pennsylvania, Philadelphia, Pennsylvania, 19104.

Q. By whom are you employed and in what capacity?

A. I am Associate Professor of Public Policy and Management and Director of the Policy Modeling Workshop of the Wharton School, University of Pennsylvania.

Q. For whom are you testifying in this case?

A. The City of Philadelphia.

Q. Have you prepared or had prepared, under your direction and supervision, any exhibits to support your testimony?

A. Yes, I have. This document consists of testimony and two appendices:

Appendix I: Curriculum Vita of Arie P. Schinnar

Appendix II: List of Economic Sectors

Q. What is your professional and educational background?

A. My professional background is outlined in my curriculum vita, Appendix I.

Q. Could you highlight aspects of your professional background that are most relevant to your testimony in these proceedings.

A. My testimony addresses various aspects of economic forecasting, regional and urban modeling, and energy policy and management. At the Wharton School I teach doctoral-level courses on policy modeling dealing with techniques of forecasting and policy analysis. In the Energy Policy and Management program of the University of Pennsylvania I teach courses on

economic aspects of energy policy and management. I have also supervised many doctoral dissertations on regional modeling and energy policy. I have directed and collaborated on research projects on community development, housing, urban and public services, and on forecasting the impact of federal fiscal policy on regional employment. In the course of my research collaboration with colleagues at the Energy Center of the University of Pennsylvania, I have co-authored reports and publications on generation efficiency of United States and Pennsylvania electric utilities (prepared for the Pennsylvania Governor's Energy Council), on international comparisons of management efficiency of electric utilities, on household energy use, conservation policy and oil imports in Jamaica, on oil supply in the South Pacific, and on energy prices and substitution among primary factors of production. Most recently, I have directed a study by the Wharton Policy Modeling Workshop, commissioned by the City of Philadelphia, to assess the impact of PECO's proposed electric rate increases (the "PECO Rate Proposal") on the Philadelphia area economy.

Q. What is the Policy Modeling Workshop of the Wharton School?

A. The Policy Modeling Workshop (Wharton PMW), is a research unit of the Wharton School affiliated with Wharton's Department of Public Policy and Management. It was created in recognition of the increasingly important role that mathematical models and computer methods play in the development of policy throughout the public and private sectors. Utilizing advanced computer technology and drawing on current findings in the fields of management science, economics, operations research, and statistics, Wharton PMW conducts original research into the formulation of models to support and supplement policy analysis and to test management decisions. The present focus of PMW's research includes (a) economic forecasting and (b)

the analysis of productivity. Forecasting economic performance and legislative tracking entails the development of models of national and regional economies to assess the impact of government policy on employment, industrial activity, commodity prices and trade. The analysis of productivity in government and industry entails the development and application of methods for measuring productivity and effectiveness of government operations and services, and of managerial efficiency in industry.

Q. Have any previous Wharton PMW studies dealt with the Philadelphia economy?

A. In recent years a number of our research activities have focused on the Philadelphia area, including the development of a model of the Philadelphia SMSA economy designed to forecast the impact of various local conditions on interregional mobility of labor and capital and on the relocation of industry. In March 1985 the City of Philadelphia commissioned an adaptation of this model to analyze the economic impact of PECO's Rate Proposal. This adaptation will be referred to as the Philadelphia SMSA STARLOC Model, or STARLOC.

Q. Would you briefly review for us the principal components of STARLOC.

A. Figure 1 gives the structure of the model. It breaks down into these components:

- A model of the Philadelphia Standard Metropolitan Statistical Area (Philadelphia SMSA) economy. The Philadelphia SMSA includes Philadelphia, Bucks, Chester, Delaware and Montgomery (PA.) counties, and Burlington, Camden and Gloucester (N.J.) counties. The regional economy is divided into 23 manufacturing and non-manufacturing sectors. Information on

employment is divided by these 23 sectors, by 7 occupational groups and by 6 income groups. Household consumption in the model is divided into 6 income groups and 17 consumer products, including energy expenditures by fuel type.

- Growth and Price submodels that project by sector patterns of job growth and price-inflation, as well as exports, imports, investment and government expenditures.

- Energy (electricity, gas and fuel oil) demand elasticities describing the response of ratepayers (23 business sectors, residential ratepayers by income and government) to electricity price increases.

The STARLOC model includes nearly two-hundred equations and over one thousand parameters detailed in a technical report to be submitted to the City of Philadelphia (see Note 1). STARLOC was presented before faculty and graduate students of the Wharton School in a seminar and has been used extensively in graduate course work on energy policy simulation; its interindustry multipliers were also presented at a recent meeting on regional multipliers held at the Philadelphia Federal Reserve Bank.

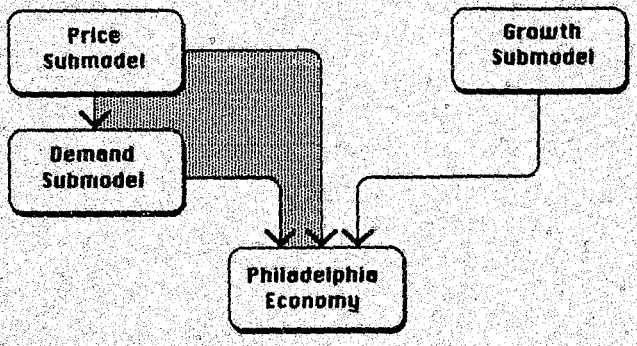


Fig. 1. Components of STARLOC

Q. What was the purpose of the study commissioned by the City?

A. The object of the study was to search for an electricity rate policy that would balance PECO's stated need for revenue increases with the Philadelphia region's need for sustained economic growth. The analysis focused on the following questions:

- What will the impact of the PECO Rate Proposal be on job growth in the Philadelphia regional economy?
- If there are adverse effects, which sectors of the economy, occupational groups and household groups will be most affected?
- What will the increases in electricity bills and other energy costs be for industry, commerce, residential ratepayers, and City government?
- How will the City government's finances be affected?
- Is PECO's Rate Proposal, including its phase-in schedule, feasible in light of economic trends and conditions?

Q. What is the purpose of your testimony?

A. To report on the findings of our study as they apply to PECO's Rate Proposal, including its proposed three-year phase-in period, and to present alternatives which allow PECO to recover necessary revenues but avoid the adverse economic impact of large rate hikes.

Q. Would you please summarize your findings.

A. The effect of the implementation of PECO's Rate Proposal, obtained through simulations with the Philadelphia STARLOC Model, is a loss of new job growth by as much as 19,000 new jobs by the end of the three-year phase-in period. 8000 of these new jobs lost would be lost in Philadelphia. Most of the loss will be in the service sector of the economy. Among ratepayers, lower-income residential ratepayers would the most severely affected. The City's financial burden will increase by $16 million annually. And for PECO

to attain its revenue goals, the United States economy will need to sustain a 3% annual growth rate over the three-year period, assuming the inflation rate persists at an annual rate of 4%. The analysis also shows that a longer phase-in period substantially reduces the adverse economic effects to the Philadelphia region of the price hike.

Q. How serious are these adverse effects?

A. These adverse effects are very serious indeed and deserve careful attention, particularly when we consider that the Philadelphia area has a long track record of slow economic growth, averaging about 1.1% between 1972 and 1983. A viable local economy is as important to PECO as a viable electric company is to the local economy, and our present local economy cannot afford the harm the proposed rate hike would inflict.

A number of economists who have regularly studied this area's economy, such as Professor Anita Summers of Wharton and Dr. John Gruenstein of the Philadelphia Federal Reserve Bank, see Philadelphia at an important economic turning point now, when "most of the unfavorable influences on employment in the Philadelphia region during the last three decades have lessened or become favorable" (direct testimony of Anita Summers, 3 December 1984, Limerick Unit No. 2 Generating Station Investigation hearings, Docket No. I-840381, PECO Statement No. 3, p.3-3). Testifying at PECO's invitation a year ago, Professor Summers suggested that a growth rate in area employment of 1.1% annually over the next decade would be a conservative estimate, while 2% is more likely. Her assessment did not, however, include or reflect the magnitude of PECO's Rate Proposal.

Our model forecasts show that the area economy will grow at an annual rate of 1.9% without the proposed rate increase and then only if the U.S. economy sustains a 3% growth rate. If the performance of the national

economy is more sluggish, with a growth rate of, say, 2.5% over the next three years, then the Philadelphia area's growth rate will be only 1.5% (the figure PECO assumes in these hearings). Add PECO's proposed rate hike to the local economy and the local growth rate drops to 1.2%. This is a significant drop, a reversal of the considerable gains made in the local economy recently and in line with Professor Summers' most conservative estimate of growth. The combined effect of a worsened economy, sluggish growth in employment opportunities, and a higher financial burden on low-income households is in itself a cause for serious concern.

Q. What do you believe could be done to avert these adverse economic impacts?

A. Assuming that the 28.2% rate increase to recover the capital and operating costs associated with Limerick Unit 1 is fully justified, a phase-in period is necessary in order to reduce the adverse impact of the rate increase. Indeed, the manager of PECO's Rate Division explained the Company's reason for proposing a three-year phase-in period of the 28.2% rate increase: "The Company recognizes that this is a significant rate increase and presents this phase-in proposal in an effort to reduce the impact of this increase on ratepayers and the economy of the Company's service territory" (Raymond C. Williams, Manager, Rate Division of PECO, PECO Statement No. 17, September 1985). Three years is too short, however, to avert the economic hardship caused by the rate increase. **If the inflation rate persists through 1989 at the current level and the electric rate increase does not exceed 28.2%, I recommend extending the phase-in period to a minimum of six, preferably seven, years.** Such a phase-in period would reduce virtually to zero the real increase in the price of electricity.

Q. What factors did you consider in arriving at this conclusion?

A. The key factors are 1) the electricity rate increase, 2) the phase-in period of the rate increase, 3) the inflation rate, and 4) the growth-rate of the economy. The rate increase and the phase-in period are policy instruments to be determined through these hearings, while the inflation and growth rates are entirely beyond our control; yet all four factors are closely interdependent.

The inflation rate and the electric rate increase jointly determine the real increase in the price of electricity. For example, if the annual hike in electric rates is 9% and the annual inflation rate is 6.5%, as PECO projects, then the real electricity price increase is roughly 9% minus 6.5%, or 2.5%. On the other hand, if the annual inflation rate persists at its present level of 4%, then the real increase in the price of electricity would be roughly 9% minus 4%, or 5%, twice that of the real increase under the higher inflation rate of 6.5% (see Note 2). So no matter how carefully one determines the exact electric rate increase, the severity of its impact still depends on the inflation rate (see Note 3).

Q. How does the change in the real price of electricity affect the economy?

A. In two principal ways. First, the level of demand for electricity in the economy depends in part on its price relative to the price of other energy fuels, such as gas and oil. A price hike in electricity may lead to both fuel substitution and energy conservation, reducing the demand for electricity and lowering the revenues the price hike had been designed to achieve.

Second, a substantial electric price increase may cause a local inflation spiral, however small, that would be reflected in the price of

goods and services produced by the economy. The demand for local exports and the level of local consumption may then drop, causing loss of employment opportunities and business revenues. The economy thus weakened would limit PECO's revenue growth.

Q. What effect does the growth-rate of the economy have on this?

A. PECO's ability to secure its requested revenue level also depends on the growth rate of the local economy, which by and large is beyond our control. If the national economy is booming, inducing fast expansion in the local economy, the loss in electricity demand due to a price hike may well be offset by economic growth. On the other hand, if the national economy is sluggish and the local economy nearly stagnant, then the slow growth of the economy may not be sufficient to offset the decline in electricity demand. The shortfall of revenues thus produced would necessitate still further increases in electric rates.

Q. Please explain how all of this is affected by the phase-in plan.

A. When a 9% annual increase in the price of electricity is compounded over a three-year period, as PECO is proposing, then the overall increase is $(1.09)^3 = 1.295$, or 29.5% (the rate increase PECO is planning for most ratepayers). The same increase of 29.5% can be achieved with a 6.67% annual price increase compounded over four years, $(1.0667)^4 = 1.295$, or a 5.3% annual increase compounded over five years, or a 4.4% increase compounded over six years. The tradeoff between the phase-in period and the annual electric rate increase is shown in Table 1. All scenarios shown yield a 29.5% rate increase at the end of the phase-in period. Observe that under a 5% inflation rate, for example, PECO's three-year phase-in period results in a 4% real price increase per annum, but a five-year phase-in period would produce a negligible 0.3% real price increase.

TABLE 1

ALTERNATIVE PHASE-IN PLANS:

	PECO'S PHASE-IN PLAN			ALTERNATIVE PHASE-IN PLANS		
Inflation Rate	Phase-in Period (yrs.)	Nominal Rate Increase	Real Rate Increase	Phase-in Period (yrs.)	Nominal Rate Increase	Real Rate Increase
4%	3	9%	5%	6	4.4%	0.4%
5	3	9	4	5	5.3	0.3
6.5	3	9	2.5	4	6.67	0.17

Q. How would economic growth affect these figures?

A. In the case of PECO's three-year phase-in plan, the 4% real price increase will result in a considerable drop in demand for electricity. Growth in the economy would have to be sufficiently high to offset the drop in demand in order to achieve the 29.5% rise in revenues. Under the alternative five-year phase-in plan, demand is stable and growth in the economy would produce increased revenues beyond the expected 29.5%. These additional revenues could be used either to moderate the electric rate increase or to recoup a portion of the unrecovered revenues which accrued over the phase-in period. The important difference between the two phase-in plans is that under PECO's three-year plan the economy will be adversely affected, whereas under the five-year plan there will be negligible adverse effects.

Q. How would the phase-out period differ under the different plans?

A. The phase-out period will be used to recoup the unrecovered revenues caused by delayed billing and collection of a portion of the approved rate increase. Table 2 shows the backlog in revenues accumulated over the phase-in period that PECO has asked to recoup during the phase-out period, excluding carrying costs, which the Company has agreed to forego (see Note 4).

TABLE 2

ALTERNATIVE PHASE-OUT PLANS:

Phase-in Period	Phase-in Rate* Increase	Unrecovered Revenues as % of Pre-Phase-in	Unrecovered Revenues as % of Post-Phase-in	Minimum Phase-out Period	Phase-out Rate* Increase
3 yrs.	9%	31.2%	24.1%	3 yrs.**	8.0%
4	6.67	46.2	35.7	3	5.8
5	5.3	61.4	47.4	4	4.6
6	4.4	77.0	59.5	5	3.8

*compounded annually

**PECO's proposal (first row) shows a single rate increase applied for a three-year phase-out period

Thus in the case of a three-year phase-in, the deferred revenues would amount to 31.2% of the pre-phase-in level of revenues, while in the five-year plan the backlog will be nearly double that amount, 61.4%. The fourth column in the table provides the backlog in revenue expressed as a percent of the level of revenues at the end of the phase-in period (post phase-in). The remaining two columns list both the length of the phase-out period and the annual rate increase necessary to recoup the unrecovered revenues (see Note 5).

Figure 2 charts the annual electric rate increases under each phase-in, phase-out plan as a percent of the base year rate (1985). Note the faster pace of rate increase under PECO's plan, compared with the alternative plans. For example, under PECO's plan, by 1989 the electric rate will have risen 37.5%, whereas under a 6-year phase-in, 5-year phase-out plan this price level will be realized in 1993.

Of the four scenarios listed in Table 2, the first is essentially PECO's proposal, the other alternatives are as follows: If we accept the 6.5% inflation rate assumed by PECO, a four-year phase-in and three-year phase-out period would render negligible the impact on the economy; if

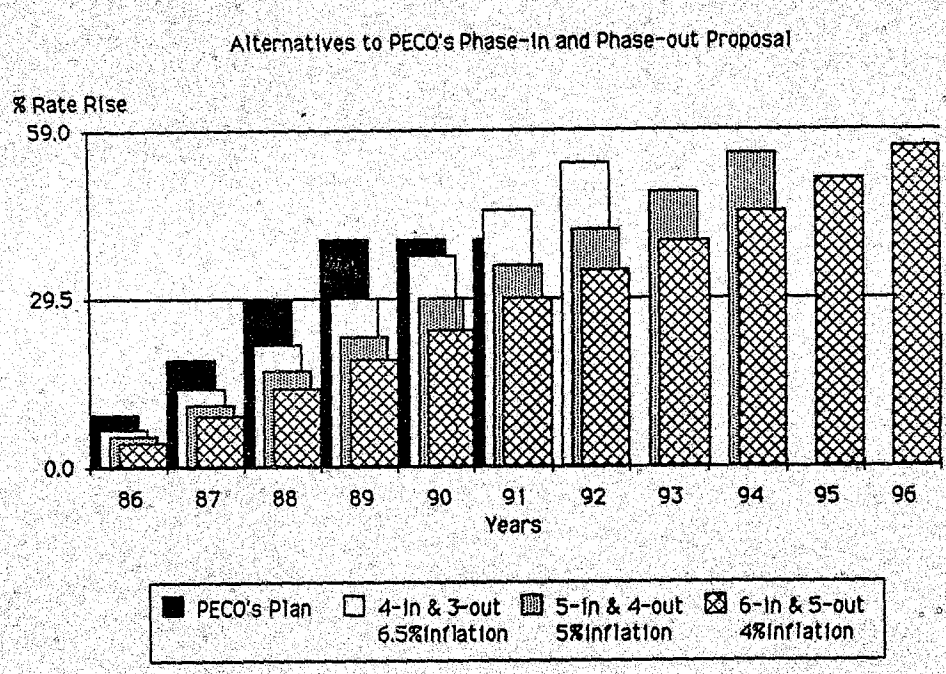


Fig. 2

inflation is lower than 6.5%, say 5%, then a five-year phase-in and four-year phase-out would be preferable; and with a 4% inflation rate, the rate we anticipate, a six-year phase-in and five-year phase-out least adversely affects the economy.

Q. What is the outlook for inflation and economic growth over the next three years?

A. Based on the Blue-Chip Consensus of fifty economists surveyed regularly by Eggert's Economic Enterprises of Sedona, Arizona, released December 10, 1985 and reported in the New York Times December 28, 1985, real GNP (Gross National Product) is projected for 1986 to grow at 3.1%, and the inflation measure, the CPI (Consumer Price Index), is expected to rise by 3.7%. Other economic forecasting organizations expect the CPI to persist at 4% with economic growth ranging between 1.5% and 4%.

The Wharton Policy Modeling Workshop projects growth in employment for 1986 at 3.1% if the President's tax reform proposal is enacted, and as low as 2.5% if the Gramm-Rudman budget-balancing proposal is applied. Therefore, I believe that a 2 to 3% annual U.S. growth rate over the next three years (1986 through 1989) is a reasonable range. The table below gives job growth rate forecasts for the Philadelphia SMSA obtained through STARLOC's growth sub-model.

TABLE 3

U.S. AND PHILADELPHIA JOB GROWTH RATES (WITHOUT REAL ELECTRIC RATE INCREASE):

U.S.	Philadelphia SMSA		
	manufacturing	non-manufacturing	Total SMSA*
1.0%	-3.1%	1.4%	0.4%
2.0	-1.3	1.9	1.1
3.0	0.5	2.3	1.9
4.0	2.3	2.8	2.7

*weighted average of employment growth rates in manufacturing and non-manufacturing

In view of these figures, PECO's assumed annual growth rate for the Philadelphia SMSA of 1.5% (through 1989) is reasonable, provided the U.S. economy sustains a 2.5% annual growth rate. PECO's inflation (CPI) figures of 6.4% for 1986 and 6.65% for subsequent years are a bit high: a more reasonable range would be between 4% and 5%. (See inflation discussion below at page 15).

Q. What are the implications of these growth and inflation rates for PECO and the Philadelphia regional economy?

A. STARLOC was used to simulate combinations of growth, inflation and rate increases in order to address two questions: 1) If electric rates were to rise by 28.2% over a three-year phase-in period, under what economic

circumstances would PECO succeed in achieving a 28.2% revenue increase?, and 2) What would be the impact of such an increase on the Philadelphia region's ability to sustain economic growth?

TABLE 4

PECO'S % INCREASE IN REVENUES AT END OF 3-YEAR PHASE-IN PERIOD:

Annual U.S. Growth Rate (and Forecasters*)	Annual Inflation (CPI) Rate 4%	5%	6%
1% (Sift, Oakley, Marks)	22.4%	25.3%	28.4%
2% (Arthur D. Little, Chase Manhattan Bank**)	25.5	28.5	31.8
3% (Eggert's, First Nat'l Bank of Chicago***)	28.2	31.6	34.8
4% (Evans Economics, Marine Midland Bank)	31.7	34.8	38.1

*authors of U.S. growth rate forecasts specific to 1986
**forecast is actually 1.5% ***forecast is actually 2.5%

Tables 4 and 5 show simulations of the Philadelphia regional economy under four U.S. growth rates (1%,2%,3%,4%), three inflation rates (4%,5%,6%), and with and without the electric rate increase. Table 4 gives the growth in PECO's revenues under each growth and inflation scenario; Table 5 gives the three-year cumulative growth rate in the Philadelphia regional economy both with PECO's proposed electric rate increase and without it.

TABLE 5

CUMULATIVE GROWTH IN THE PHILADELPHIA ECONOMY UNDER THE 3-YEAR PHASE-IN AND 28.2% RATE INCREASE:

Annual U.S. Growth	Cumulative 3-year Growth in Philadelphia SMSA Economy: Without Electric Price Hike*	With Price Hike, Annual Inflation (CPI) Rate 4%	5%	6%
1%	1.2%	0.3%	0.5%	0.7%
2%	3.3	2.5	2.7	3.0
3%	5.7	4.7	4.9	5.2
4%	8.1	6.9	7.1	7.4

*assumes annual rise in electric rates is commensurate with inflation

Listed along with the U.S. growth rates in Table 4 are the economic forecasting organizations cited in the New York Times, 28 December 1985, as authors of these 1986 growth projections. Though the range of projected values for the U.S. growth rate is wide, from -0.7% (Business Economics Inc.) to 5.2% (Bostian Research), the projections for inflation are nearly unanimous, from 3.2% (Marine Midland Bank) to 4.4% (Irving Trust Co.). The midpoints of the range show growth at approximately 3% and inflation at about 4%. This economic pattern will yield a 28.2% increase in revenues for PECO (Table 4, 3rd row, 2nd column). However, if the national growth rate drops below 3% (PECO assumes 2.5%) to, say, 2% per annum over the next three years, then PECO will achieve only a 25.5% increase in revenues, short by 2.7% (Table 4, 2nd row, 2nd column). This shortfall, largely due to energy conservation measures, is considered a "debt" by the company which customers "owe" them, due after 1989.

Q. What if PECO's projections on inflation and growth are correct (inflation of 6.5%, U.S. growth of 2.5%)?

A. PECO would gross a 34.75% increase in revenues, 6.55% above the targeted amount. Thus, using PECO's own economic assumptions, the requested rate increase should be reduced by 6.55%, to a level of 21.65%.

These figures are arrived at by starting with a scenario of 2% growth rate (2nd row of Table 4) and 6% inflation rate (4th column), for which PECO will realize a 31.6% increase in revenues. Then by adding 1.6% to allow for 2.5% U.S. growth and an additional 1.55% to account for 6.5% inflation rate, we obtain a 34.75% increase in PECO's revenues.

Q. And what if PECO has erred in its projections of inflation and growth rates?

A. Then the impact on the local economy provides another compelling reason to reduce the rate hike. The specifics can be seen in Table 5, where the second column gives the projected growth in the Philadelphia economy over the 3-year period without the PECO Rate Proposal price increase, and columns three through five give the corresponding growth under the 28.2% electricity price increase and three inflation rate scenarios.

If PECO's economic assumptions are wrong and inflation persists at about 4% (as it has for some time now) while the U.S. economy grows at an annual rate of 3%, then the Philadelphia economy's 3-year cumulative expansion rate will decline from 5.7% to 4.7%. This 1% slowdown over three years means a loss of approximately 20,000 new jobs in the Philadelphia SMSA. Now if the U.S. annual growth rate is lower, say 2%, then the Philadelphia SMSA three-year growth rate would drop from 3.3% to 2.5%, a 25% reduction which a region seeking to improve its performance relative to the nation can ill afford.

Q. Are you then suggesting that PECO is not justified in seeking the 28.2% price increase?

A. This issue is not one I address. I am simply saying that PECO's Rate Proposal, a 28.2% price hike over a three-year period, makes little economic sense for anyone: the Company, business or residential ratepayers. If PECO's economic assumptions are correct, as discussed earlier, then PECO will realize a 6.5% increase in revenues over and above the requested 28.2%. If the economic climate remains much as it is now (say 2% U.S. growth and 4% inflation), then the local economy will be considerably weakened in growth potential and PECO will fail to reach its revenue goal (shortfall of 2.7%). Thus, on either analysis there is a reason to modify the PECO Rate Proposal.

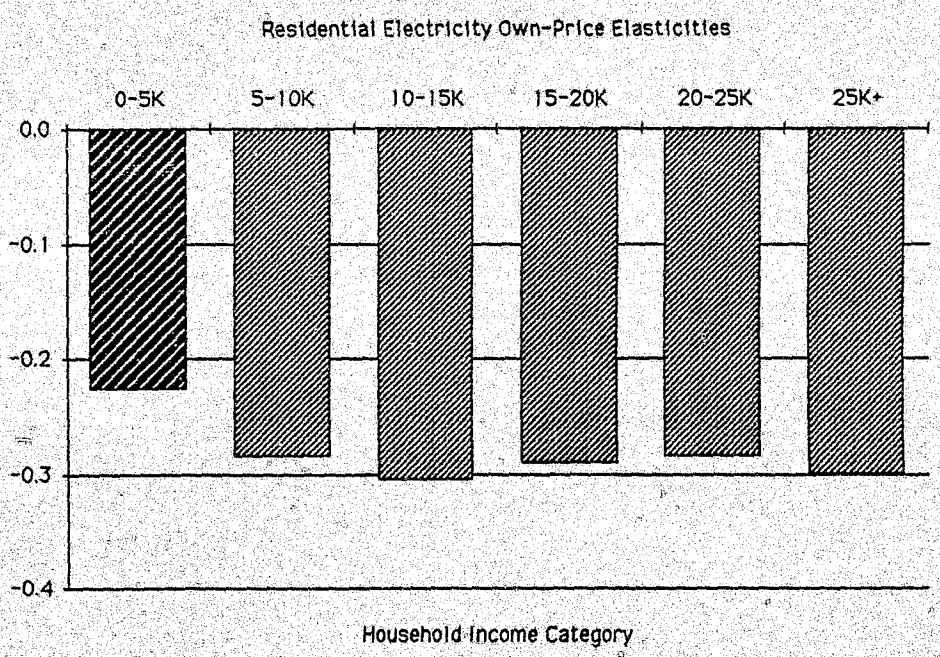


Fig. 13

for other groups. So the burden of the price increase will be heaviest on the lowest income group.

Q. How large is this group?

A. According to the 1980 U.S. Census, 18% of the work force in the Philadelphia SMSA is in this lower income group of households, and because a higher proportion of low income households are in Philadelphia, I expect that this figure is substantially higher for the City.

Q. How are the various elasticities incorporated into the model?

A. Figures 14 and 15 show the price and demand submodels in greater detail. Note in Figure 14 that the nominal rate increase undergoes adjustment for inflation and that these adjustments are industry specific to reflect the different inflation rates of each industry. Adjustments in relative prices reflecting the secondary inflation effect of electricity price increases are incorporated into the interindusty multiplier. The

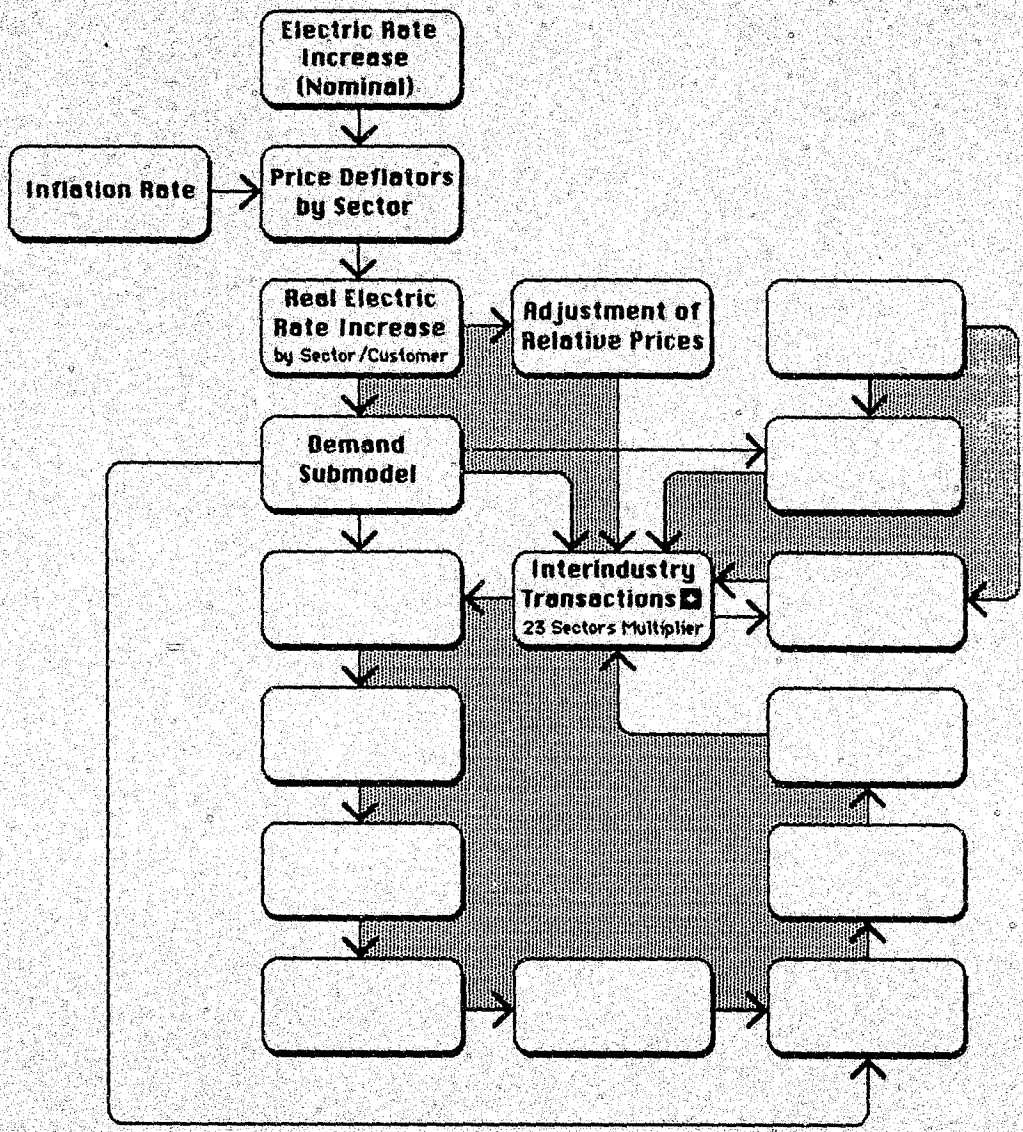


Fig. 14. Price Submodel of STARLOC

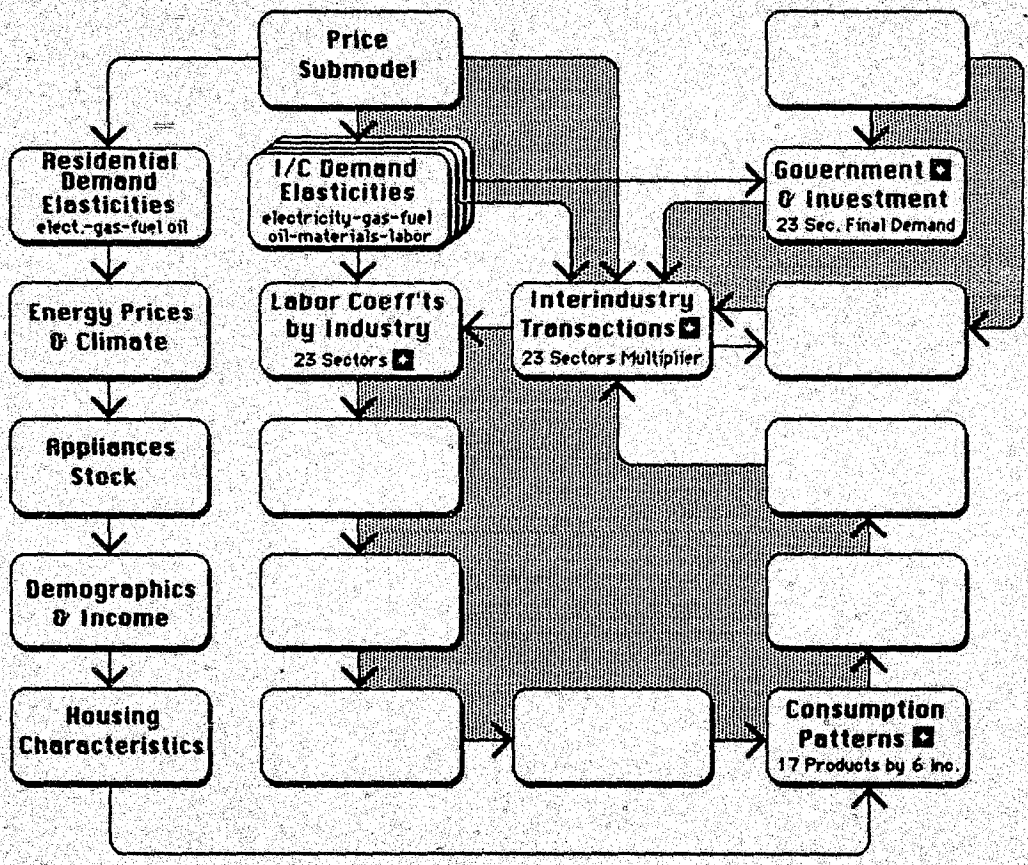


Fig. 15. Demand Submodel of STARLOC

demand submodel shown in Figure 15 performs the necessary adjustments in the technical coefficients of the interindustry transaction table, in the labor intensity coefficients of each sector, in the energy demand of government and in the pattern of household expenditures. The household component of the demand model is extensive and includes 50 variables on alternative energy prices, household income and public assistance, demographic and household characteristics, climate, dwelling structure and appliance stock.

Q. What is the City government's elasticity, and what in your estimation will be the impact of the rate increase on City government's finances?

A. I estimate an additional financial burden to the City of at least $16 million annually in 1989 and thereafter. We have estimated the City's electricity demand elasticity to be -0.2. The electric rate increase will boost the City's electricity bill by $10 million in 1989 (above the current bill of $50 million). At the same time, the decline in growth in employment resulting from the electric rate hike will reduce the City's growth in revenues from wage and other taxes by about $6 million, for a total of $16 million (see Note 8).

Q. You refer in Table 7 to short- and long-run elasticities. Would you please explain the difference?

A. Short- and long-run elasticities are intended to reflect the time period over which the economy responds to the price increase. I have usually observed long-run elasticities to be two- to three-fold larger than short-run elasticities. The magnitude of the response depends on many factors, including change in the technology and techniques of production and consumption. For example, in the case of residential ratepayers, this could reflect a change in appliance stock towards a more energy efficient end use.

The exact interpretation which one accords short- and long-term parameters also depends on the methods used in estimating them.

In the context of this discussion, I am inclined to assume that "long-run" reflects changes that might occur over a ten-year time horizon while "short-run" describes effects that might occur within five years. The simulations and results presented in this testimony reflect only short-run effects.

Q. Have you examined the long-term effects of the proposed rate increase?

A. Yes, but the results as they apply to the issue before us are largely of academic interest and have little practical use. This is so partly because the increase is likely to be phased-in through continous price hikes rather than a single price increase, and partly because, though the adverse effects on employment growth lessen over the long-run (from 19,000 new jobs lost to 14,000), strong substitution to alternative energy sources will drop PECO's revenue gains to below 20%, even though rates were raised by 28.2%. As we approach such a possibility, I expect PECO to file a series of successive price hike requests inducing a pattern of short-run responses rather than a long-term equilibrium, unless of course the shortfall of revenues is carried by shareowners and bondholders.

Q. You mentioned early in your testimony that the model has been presented in a number of professional forums and used as a teaching instrument in graduate course work. To what extent has the model been tested?

A. Before applying the model to analyze the proposed electric rate increase, the research team reviewed its performance in over one hundred simulations and conducted numerous tests of the sensitivity of the model to

fluctuations in the parameters. The tests showed the model to produce consistently reasonable and stable results. The model is complex and some parts are difficult to test, especially because we do not have precedents for a price increase of the magnitude we are considering here; nevertheless, all the tests performed were successful. Figures 16 and 17, for example, show the strong performance of the growth sub-model (see top-right portion of Figure 18) in replicating the fluctuations in growth rate of manufacturing and non-manufacturing in the Philadelphia SMSA. The model was carefully constructed, and I am satisfied that its performance is quite robust.

Q. Does this conclude your direct testimony?

A. Yes.

STARLOC Growth Submodel Performance: Manufacturing

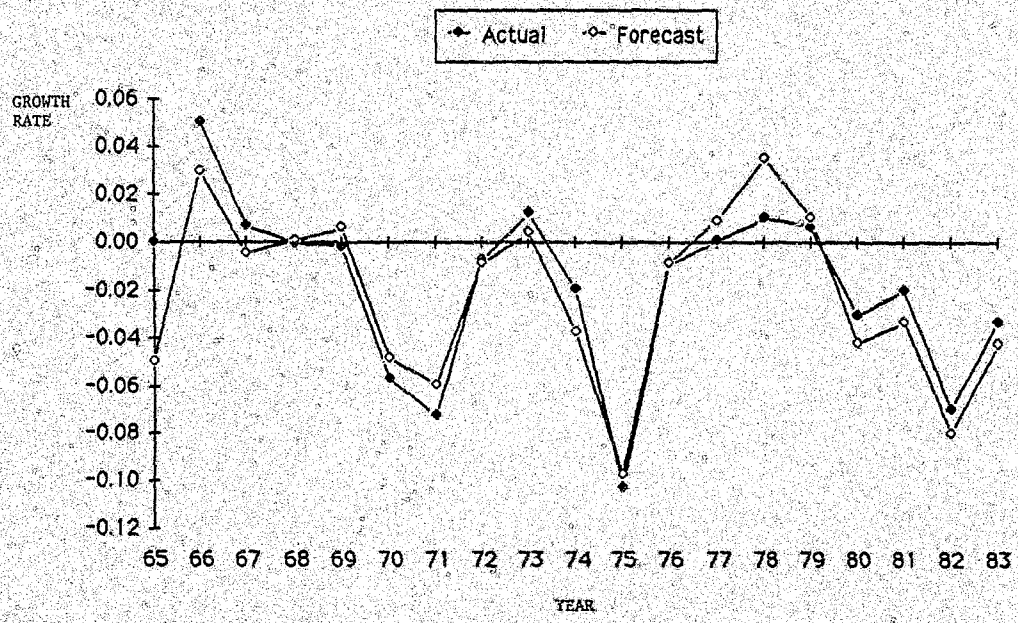


Fig. 16

STARLOC Growth Submodel Perforemance: Nonmanufacturing

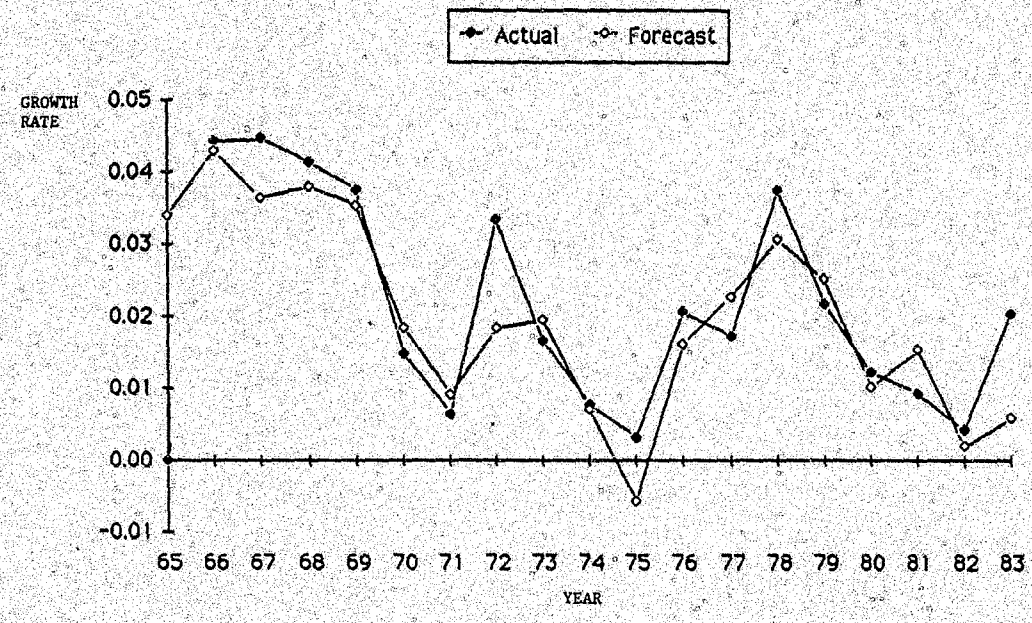


Fig. 17

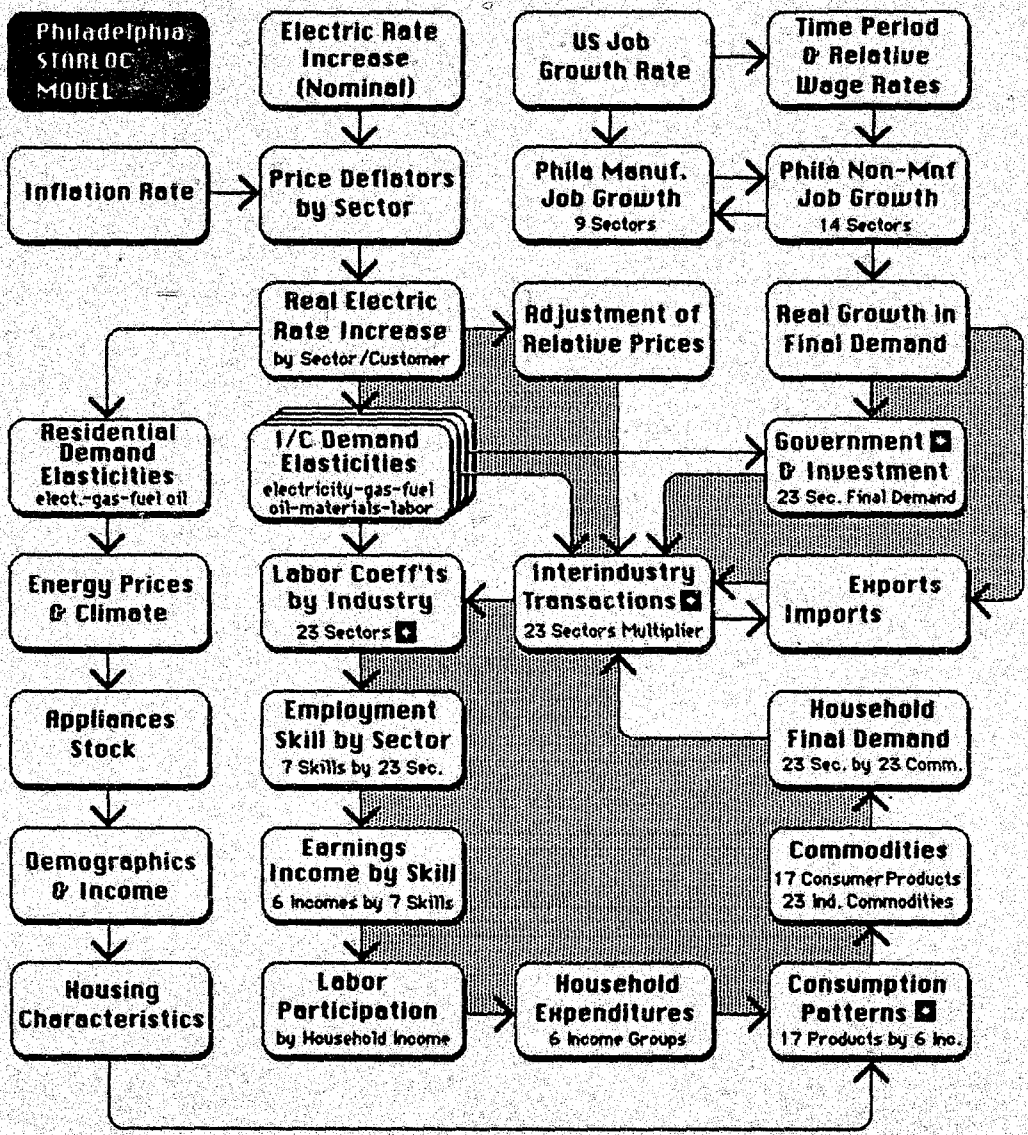


Fig. 18. The STARLOC Model

NOTES TO THE BODY OF THE TESTIMONY

1. Wharton PMW Report No. 8618, "A Model to Analyze the Impacts of Electric Rate Increases: The Philadelphia STARLOC Model Technical Report," The Wharton School of the University of Pennsylvania, (forthcoming), authored by A.P. Schinnar, L. Wood, D. Shin, P. Durongkaveroj, and M. Koved.

2. These calculations are a bit simplified. If P_e is the electricity price and P_m is the "price" of other goods and services, then P_e/P_m is the relative price, which under 6.5% inflation and a 9% annual electric rate increase translates to a real price rise of

$$\frac{P_e(1.09)}{P_m(1.065)} = \left(\frac{P_e}{P_m}\right)(1.0235) \quad \text{or} \quad \underline{2.35\%}$$

and under 4% inflation a real price rise of

$$\frac{P_e(1.09)}{P_m(1.04)} = \left(\frac{P_e}{P_m}\right)(1.048) \quad \text{or} \quad \underline{4.8\%} .$$

This is still double the real price rise under the higher inflation rate!

3. PECO assumes an inflation rate of 6.4% for 1986 and 6.65% for 1987 and beyond (Direct Testimony of Albert J. Solecki, PECO Statement No. 19, September 1985).

4. Let r be the rate of electric price increase over the base level of revenue B. Then for a τ phase-in period, the total amount of unrecovered revenues, S, in each period is

$$S = \sum_{t=1}^{\tau} B(1.295) - B(1+r)^t = \tau B(1.295) - B\sum_{t=1}^{\tau}(1+r)^t ,$$

where

$$\sum_{t=1}^{\tau} (1+r)^t = (1+r) + (1+r)^2 + \ldots + (1+r)^{\tau}$$

$$= \frac{(1+r)\left[1 - (1+r)^{\tau}\right]}{1 - (1+r)} = \frac{(1+r)(0.295)}{r} .$$

Hence

$$S = B\left[\tau(1.295) - \left(\frac{1+r}{r}\right)(0.295)\right] ,$$

where r is set such that $(1+r)^{\tau} = 1.295$.

5. In order to compute column 4 (Table 2), let B be the level of revenues at the beginning of the phase-in period, so the level of revenues at the end of the phase-in period is (1.295)B, and the unrecovered revenue as a percentage of recovered revenues at the end of the phase-in period is

$$\frac{(0.312)B}{(1.295)B} = \frac{0.312}{1.295} = 0.241$$

for the three-year phase-in row, and so on.

6. The demand equation for labor includes a price of capital parameter, thus implicitly including energy-capital substitution possibilities. Capital is largely imported, however, hence the impact of such substitution will mostly be felt in the import figures. Also, recent research findings suggest that energy and capital are complements rather than substitutes, as earlier studies erroneously hypthosized.

7. Compared with the $10-15,000 income group, the deviation of the lower income group is statistically significant at the $p > 0.01$ level. This difference is not only significant but important as well.

8. The increase in cost to the City is computed as follows: Out of a $1325 million 1984 budget, about 50% of the revenues are made up of wage and earnings taxes, or $663 million. A decline of 0.92% in jobs would produce a decrease of at least $6 million in revenues, while the City government's electricity demand, expressed as a bill of $50 million, would decline to $49 million (with an elasticity of -0.2 and assuming inflation of 4% and no increase for street lighting, implying a 10% increase in real electric prices to the City by 1989 and a 2% drop in real demand). The City would thus pay $60 million for electricity, $10 million above the current bill. The combined effect of the rate increase would be a $6 million decline in revenues plus a $10 million increase in expenditures for a total cost to the City government by 1989 of $16 million.

Appendix I

ARIE P. SCHINNAR
Curriculum Vita
December 1985

PERSONAL INFORMATION

Date of Birth: November 10, 1946

Home Address:

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Office address:

The Wharton School
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Philadelphia, PA 19104-6372
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CURRENT POSITION (The University of Pennsylvania)

1983-p Director, Wharton Policy Modeling Workshop, The Wharton School
1983-p Associate Professor, Department of Public Policy and Management, The Wharton School, University of Pennsylvania
1985-p Associate, Department of Health Policy and Management, School of Hygiene and Public Health, Johns Hopkins University

EDUCATION

1968 Pells Art School, New York
1971 B.E.D. - Environment Design, Texas A&M University
1973 M. Arch. - Architecture, State University of New York at Buffalo
1976 Ph.D. - Urban and Public Affairs, Carnegie-Mellon University

ACADEMIC CAREER

1971-73 Instructor in Architectural Design and Technology, State University of New York at Buffalo
1975-76 Instructor in Policy Planning and Forecasting, Carnegie-Mellon University
1976-81 Assistant Professor of Public Policy (SPUP) and Regional Science (FAS), University of Pennsylvania
1978 Visiting Assistant Professor, Carnegie-Mellon University
1981-83 Associate Professor of Public Policy and of City and Regional Planning, School of Public and Urban Policy, University of Pennsylvania
1981-83 Founding Director, Policy Modeling Workshop, School of Public and Urban Policy, University of Pennsylvania

CONSULTING AND OTHER

1975	Consultant, Green International Inc., Pittsburgh (regional development)
1976-80	Senior Investigator, National Planning Assoc., Washington, D.C (national goals accounting)
1977-78	Consultant, U.S. Senate, Committee on Human Resources, Washington, D.C. (legislative information systems)
1978-80	Senior Investigator, Community Development Strategies Evaluation, University of Pennsylvania (block grants and community services)
1978-79	Consultant, American Express Company, New York (seasonal manpower forecasting)
1979	Consultant, Automated Data Processing, Clifton Heights, New Jersey
1979-81	Consultant, Mellon Bank, Pittsburgh (manpower planning)
1980-81	Advisor to the Associate Provost, University of Pennsylvania (faculty planning)
1981-82	Consultant, Gulf Oil Corporation, Pittsburgh (manpower planning)
1981-83	Consultant, City of Philadelphia, Public Health Department, and Office of the Managing Director (productivity of health services, contracting of urban services)
1981-85	Consultant, U.S. Dept. of the Navy, Washington, D.C. (productivity of personnel services)
1982-85	Consultant, Division of Mental Health & Hospitals, State of New Jersey (mental health services efficiency and effectiveness)
1982-p	Consultant, School District of Philadelphia (school merit ranking and resource effectiveness)
1983	Consultant, Governor's Energy Council, Commonwealth of Pennsylvania, Harrisburg, Pennsylvania (performance regulation and efficiency of electric utilities)
1983-p	Consultant, The World Bank, Washington, D.C. (LDC urban services and international petroleum trade)
1984-p	Associate, Leonard Davis Institute of Health Economics, University of Pennsylvania
1985-p	Consultant, City of Philadelphia, Law, Commerce, and Water Departments (economic impacts of electricity ratebasing)
1985-p	Member, Executive Committee, Research Advisory Board, The J.F. Kapnek Charitable Trust, U.S.A. and Zimbabwe (international primary health care management research)
1985-p	Consultant, Battelle Columbus Laboratories, Columbus, Ohio (performance measurement)
1985-p	Consultant, U.S. Army Research Institute, Washington, D.C. (manpower policy modeling)

OTHER EXPERIENCE

1964-73	Social and political cartoonist; numerous cartoons and illustrated columns published in several newspapers in the U.S. and Israel
1964-67	Military Service; Lieutenant
1969	Designer, Agricultural Engineering Department (and freelance)
1970-71	Research Assistant, Architecture Research Center, Texas A & M University

1971 Graduate Research Assistant, Urban Systems Analysis
1973 Project Coordinator, Ambulatory Care Services Research, State University of New York at Buffalo
1972 Research Associate, BOSTI, Inc., Buffalo
1973-76 Research Associate, Institute of Physical Planning, Carnegie-Mellon University
1978-79 Principal, Class Associates, Inc., Philadelphia

AWARDS and RELATED

1969-70 Scholarship, Loeb Foundation
1970-71 Scholarship, Haikin Foundation
1970 One-Man Art Show, College Station, Texas
1971 Tau Sigma Delta, Texas A&M University
1971 B.E.D. with High Honors, Texas A&M University
1972 NIMH Study Grant, State University of New York at Buffalo
1973-76 Stipend, Ford Foundation Policy Study Grant, Carnegie-Mellon U.
1976 "Distinction" on Ph.D. dissertation
1982 M.A. (hon.), University of Pennsylvania

MEMBERSHIPS

The Institute of Management Science; American Sociological Association; American Economic Association; Regional Science Association; Society for Industrial and Applied Mathematics; Population Associations of America; Human Resource Planning Society; Society for Policy Modeling.

OTHER ACTIVITIES

Referee for the Journal of Mathematical Sociology, Journal of Regional Science, Management Science, Environment and Planning A, etc.

Chairman and Co-chairman of Conference Sessions at annual meetings of ORSA/TIMS and the Regional Science Association.

Papers presented at meetings of APPAM, ORSA/TIMS, RSA, ASA, AEA, EDRA, NATO, and other conferences.

PUBLICATIONS:

1. "U-Graph: A Decision Making Aid," in Preiser, W.F.E., (ed.), Environmental Design Research, Vol.1, Dowden, Hutchinson & Ross, 1973, pp. 519-529. Presented at the 4th International Environmental Design Research Association Conference, Blacksburg, Virginia, April 1973.

2. "A Stochastic Model of Performance for Adaptive Environments," Environment and Planning B, 1975, Vol. 2, pp. 223-243/with C. Eastman.

3. "Eco-Demographic Pareto Optimality and Associated Opportunity Cost Evaluators," in Vogt, W.G. and M.H. Mickle (eds.), Pittsburgh Conference on Modeling and Simulation, Instrument Society of America, Pittsburgh, 1975, pp.1157-1161. Presented at the 5th Pittsburgh Conference on Modeling and Simulation, Pittsburgh, April 1975.

4. "A Multidimensional Accounting Model for Demographic and Economic Planning Interactions," Environment and Planning A, Vol.8, 1976, pp.455-475.

5. "A Theorem on Homogeneous Functions and Extended Cobb-Douglas Forms," Procedures of the National Academy of Sciences, U.S.A.,Vol.73, No.10, October 1976, pp.3747-3748/with A. Charnes and W.W. Cooper.

6. "A Model for Demographic Mobilty Analysis Under Patterns of Efficient Employment, Economics of Planning, Vol.13, 1977, pp.139-173/with W.W. Cooper.

7. "Mobility and Turnover Control of Economically Active Populations," in Charnes A., W.W. Cooper and R.J. Niehaus (eds.), Management Science Approaches to Manpower Planning and Organization Design, TIMS Studies in the Management Sciences, Vol. 8, North Holland, Amsterdam, 1978, pp. 75-98. Presented at the ORSA/TIMS Joint National Meeting, Philadelphia, April 1976.

8. "An Eco-Demographic Accounting-Type Multiplier Analysis of Hungary," Environment and Planning A, Vol.9, 1977, pp.373-384. Presented at seminars at Portland State University, University of Pennsylvania, and Harvard University, April-May 1976.

9. "Query and Construction of Multi-Attribute Social Accounts," Journal of Mathematical Sociology, Vol.5, 1977, pp.239-255.

10. "Note on Krieger's Life Cycle Indicators Framework for Social Program Evaluation," Socio-Economic Planning Sciences, Vol.11, 1977, pp.291-292. (Reprinted in Administration in Social Work, 1978.)

11. "Intertemporal Eco-Demographic Interactions and Their Manpower Planning Implications," in Bryant D. and R.J. Niehaus (eds.), Manpower Planning and Organization Design, Plenum Publishing Company, New York, 1978, pp.411-426. Presented at the NATO conference on Manpower Planning and Organization Design, Stresa, Italy, June 1977.

12. "A Class of Markov Models of Social Mobility with Duration Memory Patterns," Journal of Mathematical Sociology, Vol.6, 1978, pp.61-68/with S. Stewman.

13. "The Leontief Dynamic Generalized Inverse," The Quarterly Journal of Economics, Vol.XCII, No.4, November 1978, pp.641-652. Abstract published in Zentralblatt fur Mathematik, 1980.

14. "Demographic Stipulations and Earnings in Drews Institutionalized Divvy Economy," Papers of the Regional Science Association, Vol.41, 1978.

pp.59-71. Presented at the 24th North American Meeting of the Regional Science Association, Philadelphia, November 1977.

15. "Invariant Distributional Regularities of Nonbasic Spatial Activity Allocations: The Garin-Lowry Model Revisited," Environment and Planning A, Vol.10, 1978, pp.327-336. Discussed at the University of Pennsylvania Conference on Land Use and Transportation Models, June 1977.

16. "A Demographic Turnpike for Long-Range Manpower Planning in Developing Economies," in Ijiri, Y., and A. Whinston (eds.), Quantitative Planning and Control, Academic Press, 1979, pp.165-183. Presented at the XXIV TIMS International Meeting, Hawaii, June 1979.

17. "A Method for Computing Leontief Multipliers from Rectangular Input-Output Accounts," Environment and Planning A, Vol.10, 1978, pp.137-143.

18. "Eigenstructure, Multiplier and Game Characterizations of Administrative Personnel Requirements and Activities," Socio-Economic Planning Sciences, Vol.12, 1978, pp.185-190. (Implemented for the American Express Company, New York, 1979.)

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ECONOMIC SECTORS

1. Agriculture and mining
2. Contract construction

Manufacturing

3. Food; tobacco; textiles; apparel and fabrics
4. Lumber and wood, furniture and fixtures
5. Paper and allied products; printing and publishing
6. Chemicals, rubber and plastics; leather and leather products
7. Petroleum and coal products
8. Stone, clay and glass; miscellaneous manufacturing
9. Fabricated and primary metals
10. Machinery and electrical equipment
11. Transportation equipment and instruments

Non-manufacturing

12. Transportation and communications, excluding railroads
13. Wholesale trade
14. Retail trade
15. Finance, insurance and real estate
16. Advertising and business services
17. Health services
18. Educational services
19. Other services (personal care, legal, etc.); government enterprises; water supply and sanitary service
20. Railroads and related
21. Electric utilities
22. Gas utilities
23. Hotels and lodging places

26/26

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STARLOC Model Specifications

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SECRETARY'S OFFICE
Public Utility Commission

Computer Program

Dynamic Runs

Growth=0,1...4%

purpose:

forecasts of economic impact in aggregate figures, comparing various economic conditions

inputs: automated

multiple combinations of
rate increases (28.2, 37.6%...)
inflation rates (4,5,6%...)
phase-in periods (3,4yrs...)
growth rates (0,1,2,3,4...)

outputs:

tables 4 and 5
multiple scenarios

DOCKETED
FEB 24 1986

DOCUMENT FOLDER

Comparative Statics for 1981

Growth = 0

purose:

detailed economic impact analysis by sector, skill, income and region

inputs: manual

rate policy by ratepayer
Inflation rate (single)
time period (single)
Growth rate = 0 always

outputs:

figures 4,5,6,7,8
one scenario