PECO Statement No. 15

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

DIRECT TESTIMONY OF
WILLIAM H. HIERONYMUS

STANDARDS FOR DETERMINING THE RATEBASE TREATMENT OF LIMERICK UNIT NO. 1; COMPARATIVE EVALUATION OF LIMERICK SCHEDULE; THE PRUDENCE OF DECISIONS TO CONTINUE LIMERICK CONSTRUCTION

27 September 1985

TESTIMONY OF DR. WILLIAM H. HIERONYMUS

Q. Please state your name, business affiliation and address.

A. My name is William H. Hieronymus. I am a Director of the firm of Putnam, Hayes & Bartlett, Inc. (PHB). My office address is 124 Mt. Auburn Street, Cambridge, Massachusetts 02138.

Q. What is your educational background?

A. I received a B.A. in social science from the University of Iowa in 1965, a Masters Degree in economics from the University of Michigan in 1967, and a Ph.D. in economics from the University of Michigan in 1969.

Q. Please outline briefly your occupational history.

A. While completing my graduate studies, I worked for the Institute of Science and Technology on industrial forecasting and for the U.S. Department of the Treasury on business taxation policy issues. Following graduation I was in the U.S. Army. My primary assignment was in cost analysis; my duties encompassed cost/benefit analysis, cost forecasting and procurement policy studies. I then joined Systems Technology Corporation for which my primary assignment was developing a cost/benefit methodology for the Occupational Safety and Health Administration.

Early in 1973, I joined Charles River Associates as a Senior Research Associate and, later, Program Manager for energy market analysis. My primary responsibility was the direction of studies of supply, demand and price forecasting for electricity and electric utility fuels.

In 1978, I joined PHB. At PHB I have specialized in utility economics, focusing in particular on electric utility planning and regulation.

Q. Dr. Hieronymus, what general subject area does your testimony in this proceeding cover?

A. My testimony can be grouped into three general subject areas. First, I will discuss the standards which are appropriate to consideration of the ratebase treatment of Limerick Unit No. 1 from the perspective of a utility economist. Second, I will assess the reasonableness of the Limerick Unit No. 1 construction schedule relative to other plants. Third, I shall discuss the prudence of PECO's decisions to continue constructing the Limerick station over the period from 1975 through 1980. In particular, I will assess the reasonableness of the load forecasts and capacity planning assumptions used by PECO over that period.

Q. Have you testified previously on the issue of appropriate standards for recovering the costs of utility generating investments?

A. Yes. I discussed this topic at length in three previous cases concerning newly completed nuclear plants: Missouri Docket No. ER-84-168 (also filed in Illinois Case No. 85-0006), FERC Docket No. ER-84-560 and Arkansas Docket No. 84-249-U.

Q. Your second topic is the schedule of Limerick Unit No. 1 relative to other plants. What is the basis for that analysis?

A. Over the past four years, I have directed development and continuous updating of PHB's proprietary database of nuclear plant costs and schedules. That database forms the basis of my schedule testimony in this proceeding.

Q. Your third topic area is the prudence of PECO's past decisions to continue constructing the Limerick station. Have you testified previously concerning appropriate methods for assessing completion versus cancellation of nuclear plants?

A. Yes. I testified before the Joint Committee on Nuclear Alternatives of the Michigan State Legislature concerning the construction plans of Consumers Power Company and Detroit Edison Company; before the California Public Utilities Commission in application No. 59308, a Certificate of Need hearing concerning a large coal-fired station jointly proposed by Pacific Gas and Electric and Southern California Edison; before the Michigan Public Service Commission in Case No. U-6360, in which the primary topic was completion of the Midland nuclear generating station; before the Pennsylvania Public Utility Commission in Docket No. I-80100341 concerning the economic consequences of completing the Limerick nuclear station; before the Public Service Commission of the State of New York in Case No. 28059 concerning the economic cost implications of completing the Nine Mile Point Station; before the Maine Public Utilities Commission in Docket Nos. 81-114 and 82-5 concerning continued participation by Maine Public Service in the Seabrook nuclear station, and in Docket No. 84-113 concerning continued participation by Bangor Hydro, Central Maine Power and Maine Public Service in Seabrook Unit No. 1; before the Indiana Public Service Commission concerning completion of the Marble Hill station in Cause No. 84818; and before the Illinois Commerce Commission in Docket No. 82-0855 concerning continued construction of the Braidwood nuclear station. My direct testimony in New Hampshire Docket No. DE 81-312 dealt with the generic issue of how plant completion studies should be done. In addition, testimony in four rate cases concerning newly completed nuclear plants -- Pennsylvania Docket No. R-822169, Arkansas Docket No. 84-249-U, Missouri Docket No. ER-84-168 and FERC Docket No. ER-84-560 -- dealt with aspects of analyzing the cost of nuclear plants relative to alternatives. The latter three of these cases also assessed aspects of the prudence of the constructing utilities' past planning decisions and assumptions.

Q. Other than these studies to which you have testified, have you performed other studies relating to methods of evaluating utility supply plans?

A. Yes. I coauthored a study of this topic which formed the basis for testimony of Dr. Howard W. Pifer III, one of my colleagues, before the California Public Utility Commission in OII-26, a general inquiry into utility supply plans and planning methods. For the Electric Power Research Institute (EPRI), I coauthored a report on methods for incorporating financial and regulatory constraints into supply plan optimization models. For the U.S. Department of Energy, I coauthored a study of low-growth futures and least-cost planning for electric power supply. One chapter of that study deals with methodologies for assessing the relative costs of alternative supply plans. I have also assisted a number of public utilities in improving their planning tools and in evaluating supply options.

Q. One specific area of your investigation into PECO's past decisions to continue constructing the Limerick station which you have identified is the reasonableness of PECO's load forecasts in the 1975 to 1980 period. Can you explain the basis for your expertise in this area?

A. Yes. Throughout that period, I was heavily involved in utility load forecast model development and assessment. Of particular note were "state of the art" load forecasting surveys and analyses performed for EPRI in 1976 and the Federal Energy Administration/Department of Energy in 1978 and the low growth futures study previously noted.

Q. Would you please summarize the major conclusions of your testimony?

A. In the first section of my testimony I conclude that the prudent investment standard is the primary or even sole standard which should be used in determining the regulatory treatment of Limerick Unit No. 1. Only if other aspects of regulation were substantially altered would other standards be equitable or likely to create appropriate incentives for utility managements. I conclude in particular that where prudent investment and excess capacity standards conflict, primacy should be given to the prudence standard.

If excess capacity is maintained as a separate test, I conclude that fair ratemaking which is designed to provide economically appropriate incentives must recognize that the minimum reserve which meets reliability needs cannot be the maximum reserve allowed for ratemaking purposes. The reserve for ratemaking purposes must recognize that units cannot be added in blocks which match annual load growth and also must recognize that a standard based on perfect foresight in load forecasting is unreasonable. Taking either or both of these factors into account results in an allowable reserve margin well above the minimum which is required to meet reliability needs on an annual basis.

I also discuss the role of after-the-fact analyses of whether the unit will pay for itself prospectively in the context of the prudence and used and useful standards. I conclude that whether net benefits today appear likely or not is irrelevant to and, indeed, in sharp conflict with, the prudent investment test.

Moreover, that use of such calculations for current ratemaking purposes is quite undesirable on numerous additional grounds.

In the second section of my testimony, I conclude that the length of time required to construct Limerick Unit No. 1 was typical for plants of its vintage, despite delays in the publicly announced schedule in the mid-1970s which have been much complained of in earlier proceedings. The reason becomes clear when the extraordinarily excellent adherence to announced schedule in the post-TMI period is contrasted with the typical nuclear plant construction schedule performance.

In the third section of my testimony, I conclude that during key periods PECO frequently assessed the ratepayer benefit from completing Limerick relative to alternative baseload options, and that it was reasonable to rely on those studies in concluding that Limerick should be completed. This conclusion is based in part on an examination of the assumptions which underlie PECO's studies relative to a number of other studies conducted at that same time and, in part, on examination of potential biases in the PECO study methodology. I conclude that PECO's assumptions were reasonable and conservative with respect to other contemporaneous assumptions and that the PECO methodology used in the 1970s significantly understated the benefits of Limerick completion. On the basis of this examination, I conclude that the decision to continue construction of Limerick was prudent.

Standards for Ratebase Exclusion

Q. You have stated that you would be discussing appropriate standards for deciding whether the costs of Limerick Unit No. 1 and associated common plant should be recovered by PECO. What is the purpose of this section of your testimony?

A. The purpose of this section of my testimony is to, first, explain the economic content of the prudence standard and, second, the reasons why alternative standards for determining whether investments undertaken on behalf of ratepayers should be allowed in rates are pernicious in their economic effects and necessarily inequitable as applied in practice.

I am mindful that there is a substantial legal as well as economic content to these concepts and it is not my intent to intrude on legal matters which are properly addressed in briefs. However, regulatory rules and concepts, whether drawn from law or economics, are the matrix in which utilities make decisions and, collectively, are the implicit social contract upon which utility investors rely. The response of utility managements and investors to the incentives inherent in alternative schemes of regulation is an economic issue, though we shall see that the common sense of the law as represented by public utility commission decisions and the common sense of economics tend to reach the same conclusions.

Q. Before turning specifically to your discussion of the prudent investment test, could you provide a general context for your view of how it should operate?

A. Yes, I believe so. At the risk of belaboring the obvious, electric utilities are regulated exclusive franchises. In return for the franchise, the utility agrees to undertake such investments as are reasonably thought to be required to meet the needs of its customers. It further agrees to submit to a system of rate-of-return regulation in which rates are determined by regulators rather than in the marketplace.

In deciding among alternative systems of rate regulation, it is useful to keep in mind the basic goals of the regulatory process, two of which are relevant to the instant proceeding. The first goal is to assure that the needs of the utility's customers are met. In turn, this requires that the utility be able to attract the necessary capital. This "capital attraction" function of regulation demands that investors have a reasonable expectation of earning the market required rate of return on funds invested in the enterprise. The shorthand for this principle is that the regulatory process should yield returns that are fair and equitable to investors.

The second basic goal of regulation is to assure that rates are fair and equitable to ratepayers. In turn, this goal requires that utility management reasonably husband the resources provided to them by ratepayers. This is the "incentive-efficiency" function of regulation; the goal is sometimes stated as providing electric service at the least cost which is reasonably achievable.

In general, these goals could be pursued under many radically different forms of regulation and relationships between the regulator and regulated. In the American system of electric utility regulation, two basic precepts have tended to restrict the role of regulation in utility decisionmaking:

- For the most part, electricity is provided by privately managed corporations. Regulators do not seek to substitute for the decisions of management. Instead, regulators seek only to monitor management actions either concurrently, as in the issuance of Certificates of Need and in the I-80100341 Limerick investigation, or retrospectively, as in an inquiry connected to an in-service rate case. The purpose of the inquiry in either event is to assure themselves that utility management's decisions are reasonable. It is this monitoring function of regulatory involvement in utility management which gives rise to the "prudence" test for ratebase inclusion of utility investments.

- The American system of public utility regulation is based on rate-of-return regulation. Rates are cost based; revenue requirements are based on a formulaic passthrough of operating costs plus a return of and on prudently incurred investments. A crucial corollary to this point is that public utility regulation does not seek to mirror the outcome of a competitive marketplace. Ratepayers, not shareholders, are the primary beneficiaries of particularly fortunate utility investments, and, collaterally, also must pay the cost of service connected with prudent investments which turn out to be nonoptimal.

I believe that this summary of the general context of utility regulation fairly sets forth the context in which any deviation from a firm and literal application of the prudent investment standard must be evaluated. I should note that this description fully comports with the view of Alfred E. Kahn, the noted utility economist:

> The essential basis of public-utility regulation is an implicit bargain between consumers and investors that, in exchange for a monopoly franchise, the company accepts the strict legal obligation to serve all customers on reasonable terms.

> This means that shareholders accept a return on investment equivalent only to something like the market cost of capital -- the minimum that investors must see a reasonable prospect of earning if they are to put up the necessary funds -- along with the duty conscientiously to anticipate the future needs of the public and to make whatever investments may be necessary in order to meet them efficiently.
>
> This means that if the company makes a particularly successful investment -- and there have been many such -- the lion's share of the benefit goes to the consumer: Retail electric rates actually dropped 12% between 1950 and 1970; and while this drop was more than wiped out in the years that followed, rates still declined more than 20% in real terms between 1950 and 1984.
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> The other side of the bargain is, and has to be, that investors are permitted to earn the same minimum return also on the dollars that they put into investments that turn out sour. If they can earn the cost of capital only on the successes and not on the failures, it follows that they will earn less than the cost of capital on all their dollars, taken together. And investors won't play that game once they understand that those are going to be the rules.
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> (Wall Street Journal, 15 August 1985.)

The dichotomy between rate-of-return regulation based on the historic cost of prudently made investments and a more market-oriented method of regulation is not, *per se* essential. For much of the pre-World War II period, commissions relied instead on the more market-oriented "fair value" concept of ratebase. Nor is historic cost-based ratemaking necessarily the only or even necessarily the best form of regulation. However -- and I believe that this "however" is a key to any fair and economically sound departure from a firm and full reliance on the prudent investment standard for determining ratebase -- any departure from it must meet three conditions:

- First, due notice must be given. Utility investors necessary rely on the stability and continuity of the regulatory process in advancing the funds required to build new capacity. Changes in regulatory policy which shift risks from ratepayers to investors must be made explicitly clear and are best applied prospectively only to projects begun subsequently, permitting investors to decide whether the prospective earned return is sufficient to warrant accepting the risk.

- Second, any scheme of regulation must be applied fairly and uniformly. This condition is violated if, for example, only historic cost is allowed on ratebase for those investments for which fair value exceeds historic cost while fair value concepts are applied to investments whose historic cost exceeds fair value. If property is valued at "the lesser of cost or market," investors will be denied the opportunity to earn a fair return.

- Opportunistic changes in regulatory policy designed to impose large losses on shareholders under the guise of improved regulation, should be eschewed even if the new regulatory system were otherwise fair. The compact between investors and utility customers, given the very long lives of utility investments, necessarily depends on a belief in the basic fairness of the regulatory process which transcends current regulatory precepts and a trust in the current commissioners. It is regrettable, though perhaps unsurprising, that the drumbeat in favor of market pricing of the output from new utility facilities is loudest where conventional regulatory treatment of new plants will result in large rate increases but muffled where new investments will soon lead to lower rates.

Again, these views are not uniquely my own. Professor James C. Bonbright expressed essentially these same thoughts in his landmark text:

> The meaning of "fairness" in business transactions is most clearly definable when referring to a moral obligation, which may also be a legal obligation, to avoid deception and to live up to previous commitments, expressed or implied. If judged by this test alone, any rule of rate making would be fair to investors, whatever its merits or demerits on other grounds, if it conforms to the terms, on the faith of which the investment was originally made -- fair no matter how onerous or how profitable these terms may prove to be in the light of hindsight (James C. Bonbright, <u>Principles of Public Utility Rates</u> [New York: Columbia University Press, 1961], p. 127).

The necessity to "avoid deception and to live up to previous commitments," as Bonbright puts it, is motivated by practical necessity and economic efficiency as well as "fairness." If good management is to be encouraged, the regulatory rules that motivate behavior of managers must clearly be known <u>before, not after</u> the decisions are made. Self-serving retroactive changes in the rules might be tempting, but they have no role in promoting economic efficiency, fair regulation, or "risk sharing."

Indeed, the economic principles of "risk" mean that there is no meaningful concept of "risk sharing" in a game in which there is only one rule: "No Rules." If one player in the public utility "regulatory game" retains the right to retroactively and unilaterally change the rules to reverse the results of the initial set of rules, there is no meaningful "risk premium" that can be offered to the player who is exposed to this risk. The only risks that are insurable are the ones that are based on prior understandings, not unlimited retroactive changes in the rules. If one player has the power to change regulatory rules, he must either convince the other that it will never be used, or he must invoke outside constraints that will preclude him from using it. Like Lucy in "Charlie Brown," ratepayers and regulators must convince investors that the football will not be snatched away at the last minute despite their prior promises to "play fair." Unlike Lucy, however, they can expect to get away with it only once, and so both ratepayers' and investors' interests are served by convincing both that the rules will not be changed retroactively.

The Prudent Investment Test

Q. Turning now to the prudent investment test itself, can you summarize your understanding of what it entails?

A. The meaning of the prudent investment test is cogently set forth in a recent publication by the National Regulatory Research Institute (NRRI), The Prudent Investment Test in the 1980s. On the first page of that publication, the authors stress that prudence is a concept applied to decisions -- decisions to begin a plant, to employ a particular architect-engineer, to manage construction in a particular way, to continue construction if the circumstances which led to initiation of construction change radically, and so forth. Implicit in this strong insistence on prudence being applied only to decisions is the corollary that prudence is not concerned with outcomes. Prudent decisions taken in a risky environment can and do lead to regrettable outcomes. That Jim Fixx (author of the best-selling book on jogging and health) died while jogging does not make jogging imprudent. Similarly, the fact that technology choices turn out to be other than least cost or capacity turns out to be excess on a reliability basis is not evidence of imprudence. Indeed, the recognition that the environment in which utilities make decisions is uncertain necessarily implies the possibility that prudent decisions could prove wrong and result in plants which are temporarily unneeded or nonoptimal from an economic standpoint.

The NRRI report goes on to detail five basic guidelines for a prudence inquiry:

- There is a presumption of prudence. The concept of a rebuttable presumption is, of course, a legal one. However, it is also a necessary concommitant of the American system of utility regulation as I have described it earlier in my testimony. If utility managers are indeed to manage, then they must not be subjected to penalty whenever regulators might have reached a different decision. Rather, a finding of imprudence must require a positive showing that management behaved unreasonably.

- Decisions must be judged based on "reasonableness under the circumstances which were known at the time." The content of this guideline focuses on the definition of reasonableness. Reasonableness does not require perfection but rather a standard of care and professionalism consistent with the importance of the decision as it could reasonably have been foreseen. Reasonableness can only be judged using the methods and data then available; failure of system planners to use sophisticated optimization techniques in the early 1970s or failure of financial planners to foresee changes in the tax law affecting securities are not grounds for a finding of imprudence.

- There is a proscription against the use of hindsight. The second part of the prudence definition indicates that prudence must be judged based on what was known (or reasonably knowable) at the time that the decision was made. Whether the cost and performance forecasts made for Limerick in the 1970s appear reasonable based on subsequent events and what we know or believe today is not relevant. All that is relevant is whether they were reasonable when made.

- The proscription against hindsight is not limited to avoiding use of information available only subsequent to when decisions were made in determining prudence. One must also avoid using subsequent information as a filter in deciding what information should have been regarded as important at the time or what potential risks should have been more rigorously assessed. For example, utilities cannot be faulted for ignoring high-level waste disposal costs in studies performed at a time when such costs were widely thought to be negative due to spent fuel recycling. Likewise, load forecasts cannot be faulted for failing to take into account conservation and cogeneration induced by subsequent legislation.

- Finally, the NRRI report notes that a prudence inquiry is a backward looking, factual inquiry. To demonstrate imprudence, it is first necessary to establish the specific facts surrounding key decisions including, in many cases, the decision-making process and information used by the utility as well as the content of what was "known or knowable" at the time.

Q. Why must both the decision-making process and assumptions used by the utility as well as the content of what was known or knowable be established?

A. The decision-making process, including the reasonableness of the factual bases for its analyses, are potentially relevant to a determination of whether the management processes used were prudent. The inquiry into what was reasonably known or knowable serves two purposes. First, the reasonableness of the utility's actions can be judged only against a background of what information was available to it at the time. An investigation of the assumptions, bases, and conclusions of studies performed outside of the utility in question provides a comparative basis for that judgment. Second, to the extent that a utility was arguably imprudent in failing to perform a particular study or in using a particular assumption, a prudence inquiry can legitimately ask whether the study or assumption in question mattered. If, based on what was then "known or knowable," such a study would have led the utility to reach different conclusions, the imprudent act is important. If not, then there are no adverse consequences to the ratepayer from the supposedly imprudent act.

Q. How could an imprudent act not matter?

A. Remember that imprudence is concerned with decisions. Only if the imprudent act would have led to a different decision and that alternative decision would have benefitted ratepayers does it matter. For example, if I fail to fasten my seat belt, I may be behaving imprudently. If I don't get into an accident, the imprudence is without effect.

Q. Can you give an example which relates more directly to this proceeding?

A. Yes, as a hypothetical at least. Suppose that this Commission were to find that PECO's fossil fuel price forecasts in the 1970s were imprudent in that they were made without due regard to information which should have caused PECO to forecast lower prices. As a result, its "coal versus nuclear" studies are tainted. The inquiry cannot usefully stop at this point. Before this finding of imprudence can result in a ratebase disallowance, one must first ask, what would PECO have done differently if its fuels prices had been lower? To answer this question, it is necessary first to determine what a prudent fuel price forecast would have been and second to determine whether prudent management, making its decisions based on more correct information would have made different decisions than it did. In this example, if the prudently foreseen advantage to completing Limerick was large enough that PECO would still have chosen to complete Limerick based on prudent fuels price forecasts, then the imprudence in fuels price forecasts had no effect on Limerick decisionmaking and imposed no burden on ratepayers. To borrow from another section of law regulating conduct in the public interest, a utility may be "liable" based on a finding of unreasonable assumptions, but there are no "damages" since no imprudent decisions resulted.

<u>The Used and Useful Standard</u>

Q. Are standards other than the prudent investment standard sometimes invoked in determining utility ratebase?

A. Yes. The used and useful standard is also used by many commissions in determining ratebase for purposes of computing revenue requirements.

Q. Can you explain the used and useful standard as it applies to the treatment of newly completed generating facilities?

A. Unlike the prudent investment standard, about which there is a general consensus, the used and useful standard varies widely in meaning from time to time and place to place. My understanding is that the historic restriction which allowed return only on assets which were "used and useful" was meant to distinguish utility assets from nonutility assets, thereby assuring that ratepayers were not charged for assets used in unrelated businesses. Clearly, it would be quite improper for ratepayers to be charged, for example, for the portion of a utility office building used by an unregulated subsidiary of a utility.

In jurisdictions where CWIP is allowed in ratebase, any prudent investment made in utility property is used and useful, irrespective of whether the asset has entered service. That is, ongoing construction is treated as an integral part of the utility's business and a current return is allowed.

Where CWIP is not allowed in ratebase, used and useful assets generally are restricted to those which have been placed in service, though a cancelled plant is a special case. However, in some jurisdictions, even prudent investments which have been placed in service have been denied full rate recognition. In these cases, if the utility has excess capacity on a reliability or reserve margin basis, some portion of capacity is denied a full return on a current basis. I will refer to this test as an excess capacity test to distinguish it from the more general used and useful test. In so doing, I do not mean to imply agreement with the proposition that excess capacity on a reserve margin basis is the same as not being used and useful.

Q. Is there a potential conflict between the excess capacity test and the prudent investment doctrine?

A. Yes, there is. The prudence test looks at causes -- the past decisions of utility management -- and deliberately ignores the issue of whether prudent decisions resulted in good outcomes. Conversely, the excess capacity test, as it is often applied, looks only at outcomes: excess capacity results in a current disallowance even if the decisions which led to high reserve margins were prudent.

I should note that some Commissions have refused to make excess capacity adjustments precisely because of the conflict with the prudence doctrine. This position is perhaps most succinctly stated by the Wisconsin PSC:

> The plants in question ... were committed to by the utility and certified by the commission on the basis of demand forecasts which were developed from existing usage patterns of current customers. The fact of usage and the projections derived from it have dropped does not absolve the current ratepayer from all responsibility for the reasonable planning response to his prior behavior (Decision No. 6630-ER-14, p. 25).

A decision by the Idaho Commission recognized the tension between the prudence and excess capacity criteria and also the relationship between a broadened basis for ratebase exclusions and its own responsibility to provide rates of return reflective of its policies concerning grounds for return disallowances:

> Fair Share's witness, Dr. Thomas Power, would have us terminate our analysis with the finding that Kettle Falls is not used or useful, and eliminate the plant from rate base solely on the ground that the Company's decision to build Kettle Falls turned out to be incorrect. According to Dr. Power, regulators should strive to emulate the discipline imposed upon unregulated industries by

the marketplace. Dr. Power argues that in the unregulated sector a company that builds an uneconomic plant will be forced by competitive pressures to absorb the loss resulting from its incorrect planning decision, even though the decision was reasonable and prudent when made.

We find ourselves unable to agree with Dr. Power's argument that utility shareholders should be absolutely responsible for management decisions that result in surplus capacity. Utility managers must evaluate planning criteria with an eye to the public interest as well as their own corporation's welfare. It would be unfair to subject utilities to the disciplines that obtain in the marketplace when their decisions are constrained by public service obligations that do not apply to the unregulated sector. Moreover, we have historically set utility equity returns below the returns experienced by unregulated industries in recognition of the fact that utility investments are protected from many marketplace risks. Consequently, if we adopted a strict used and useful standard for rate base decisions we would be forced to increase equity returns to reflect the additional risk associated with Dr. Power's marketplace test.

There must, however, be some constraint on the ratepayers' obligation to pay for utility investments. Idaho law provides that all utility charges shall be "just and reasonable," both to the people and to the corporation. Idaho Code §60-301; Idaho Power and Light Co. v. Blomquist, 26 Id.222, 141 P.1083 (1914). It follows that the investment decisions that determine rate levels must themselves be reasonable. If a particular decision subsequently proves unnecessarily costly, the utility must be prepared to prove that its judgment when made was reasonable, prudent, and based on bona fide considerations (Order No. 18679, pp. 9-11).

Q. Do you have an opinion as to the proper relationship between the prudence and excess capacity standards?

A. As a general matter, I believe that the prudence standard should be given primacy. Under the American system of electric utility regulation, the investor is not rewarded for superior foresight or the simple luck which results in matching loads with capacity plans originated 10 or more years ago. Any fair system of regulation must match rewards with penalties. If no extra reward is gained from prudent decisions which also turn out to be right, then there is not room in fair regulation for penalties for prudent decisions which turn out to be wrong.

This principle is particularly relevant to capacity-related penalties. If a utility is to be penalized for building too much capacity despite prudent planning, where is the symmetric opportunity for gain? Surely, proponents of excess capacity penalties would not reward a utility which built too little capacity to meet its customers' needs.

Q. Are there circumstances in which excess capacity penalties are particularly inappropriate?

A. Yes, there are. One such circumstance is where the Commission itself has certified the need for the facility. In states with certification laws, the Commission has interjected itself into the capacity planning process and made its own determination that the utility should proceed with construction. To later deny a return on an investment which it had determined should be made makes a mockery of the certification process and, indeed, of the regulatory process generally.

I recognize that a decision to initiate construction is not irrevocable and prudent management (or prudent regulators overseeing management activities on a contemporaneous basis) might decide to cancel or delay construction at a later date. Hence, a certificate of need issuance is not dispositive of the issue of whether excess capacity and prudence standards conflict. However, many commissions have the authority to initiate investigations into the need for plant under construction. Where such investigations are in fact carried out and the utility ordered to proceed forthwith to complete construction, it is grossly violative of the social contract governing the operation of regulated utilities to later penalize the utility for complying with that order on the grounds that the capacity is not needed when the plant is complete.

Q. To return more generally to the issue of excess capacity tests, what are the general implications of allowing in ratebase only that plant which is not only prudent but also not excess on reliability grounds?

A. One effect is simply to make utility investments more risky. As I shall discuss later in my testimony in connection with the putative relevance of after-the-fact calculations of the likely cost effectiveness of newly completed plants to their ratebase treatment, this higher risk will be fully reflected in a higher cost of capital. If the Commission recognizes this higher cost of capital for ratemaking purposes, the expected rate reductions from excess capacity penalties will be fully offset. This is the meaning of the maxim in economics that "there is no such thing as a free lunch." A second effect is that utility management will have a strong incentive to avoid "excess" capacity even if it means higher rates and even if it imperils reliability.

Q. If the reserve margin target set by the Commission properly matches the intended level of reliability, why would actions by utility management designed to achieve that target risk higher rate levels or unreliable operation?

A. For two reasons: the unpredictability of future loads and resource balances and the lumpiness of unit additions. As events of the past 20 years have shown vividly, forecasting loads over the periods of time required to build generating plants is a risky business. In the late 1960s and early 1970s, many utilities found themselves with insufficient capacity. More recently, load growth has been overestimated.

For these reasons, forecasts of reserve margins five to ten or more years in the future at the time construction decisions must be made are quite uncertain. If utilities plan to the target reserve margin and if their forecasts are, on average, correct, they will exceed the intended reserve half of the time and undershoot it the other half of the time. Given the manifest degree of uncertainty, these capacity excesses or shortfalls could be substantial.

The lumpiness of capacity additions also will result in substantial shortages or excesses of capacity. The capacity of a typical baseload unit equals several years of load growth. Obviously, either completion of the unit must be preceded by several years of capacity insufficiency or followed by several years of excess capacity (barring fortuitous changes in unit sales or purchases or capacity retirements).

Q. If excess capacity penalties are imposed, what incentives do these give to utilities?

A. Obviously, excess capacity penalties give utilities an incentive to minimize the risk of excess capacity. Indeed, several utilities have made it clear that they will not build new capacity without absolute and prior assurance that prudent expenditures will be fully recovered. Even if utilities are unwilling to play "chicken" with regulators to this degree, if the risk of excess capacity payments is uncompensated, utilities will seek to minimize the absolute size of investments. In general, it is a logical truism that rates are likely to be lower if the utility's sole goal is providing service at the lowest cost than if it must also concern itself with avoiding temporary excess capacity.

Q. You have discussed the incentives which excess capacity penalties give to utility management. In your view, is it appropriate for utility management to respond to these incentives?

A. Yes. It would be both naive and inequitable to expect them to do otherwise. It is absolutely proper for the regulated utility to respond to those incentives; indeed, that is the purpose of the incentives. If the Commission does not believe that the response is in the public interest, the incentive obviously should not exist. It is grossly inequitable to impose a penalty for excess capacity and also to penalize measures taken to mitigate or avoid excess capacity.

In this context, I am quite troubled by the discussion of the 1976 and 1978 Limerick construction delays in ALJ Klovekorn's Initial Decision and in the Opinion and Order of the Commission in I-80100341. Judge Klovekorn appears to be saying that, to the extent, if at all, these delays were motivated by an awareness that excess capacity might be penalized, these delays were somehow improper and imprudent. I must respectfully but vigorously disagree. If the Commission is to penalize excess capacity as not being in the public interest, then utility management has a right, even a duty, to take steps to minimize excess capacity.

Q. Assuming that excess capacity were held to be a standard for determining whether plant is allowed in ratebase which is independent of and co-equal to the prudence standard, can you define the characteristics of an excess capacity standard which minimizes the negative incentive which you have described above?

A. Yes. I believe that such a standard must have three characteristics. First, the allowed capacity margin must take into account the margin of error required by the realities of planning uncertainties. Second, provision must be made for the lumpiness of capacity additions. Third, utility investors must be allowed ultimately to recover the costs of all prudent investments.

Q. Can you first illustrate why provision must be made for the lumpiness of utility investments?

A. Yes. Exhibit WHH-1 illustrates the effect of the lumpiness of plant additions on reserve margin. For purposes of my example, I have assumed a 5,000 MW load utility with an anticipated growth rate of 2 percent. The capacity plan includes 400 MW of new capacity which is currently under construction for completion in Year 3. A 900 MW unit is scheduled for completion in Year 7. The reliability-driven required reserve is assumed to be 25 percent.

Because the required reserve is 25 percent, the actual reserve must be at or near 25 percent in each year. Given only the fact that the size of unit additions is greater than the annual growth rate in required capacity, it follows that there will be "excess" capacity in most years if the requirement to serve is always met. In my example, I have let the capacity plan fail to meet the reserve requirement in one year, implying a willingness to gamble somewhat with reliability. Nevertheless, even if the load forecast proves to be exactly correct, the prudent utility will have an average capacity excess of 236 MW in this example.

Hence, if the reserve allowed for ratemaking purposes is set at the minimum level required for reliability purposes, it is a necessary result that excess capacity penalties will result. Only a utility which consistently and deliberately ignores its requirement to serve could avoid excess capacity penalties. Hence, no utility could possibly have a fair opportunity to earn its required rate of return on its prudent investment.

Q. How could this situation be avoided?

A. The reserve allowed for ratemaking purposes could be set at 25 percent plus an amount only slightly less than the size of the unit to be added. In this way a utility could earn a return on all capacity which it needs to add in order to achieve its reliability requirements. This is equivalent to saying that because of the inherent lumpiness of capital additions, a prudent utility must time its unit additions such that a unit is added as soon as capacity would be otherwise deficient. Simply put, even with a separate excess capacity standard, a unit is "used and useful" as soon as any part of it is needed for reliability purposes. If this standard were, in my opinion improperly, to be rejected for current ratemaking purposes, capital cost recovery on that portion of prudent investment not permitted into ratebase should be deferred. Underrecovery would be balanced by putting the excluded generating capacity (including accrued earnings) into ratebase when this standard was not exceeded. While this deferral and balancing permits a lower regulatory reserve margin, it is important to remember that the underlying theory on which it is based still recognizes that a prudent utility must add capacity to meet annual minimum reserve margin constraints and that full recovery of the prudent cost of the plant is warranted even under a separate excess capacity standard.

Q. You also indicated that a necessary feature of an excess capacity standard is that it take the uncertainties of load forecasting into account. What do you mean by this?

A. It is by now obvious that load forecasts are uncertain. A utility which bases its plans on precisely meeting its reliability reserve margin targets will fail to do so half of the time even if its load forecasts are accurate on average, since "accurate on average" means that half of the time loads will be higher than forecasted and hence reserve margins lower than intended. Because electricity consumption cannot be deferred from year to year, being right on average is not good enough. A reserve requirement consistent with a one-day-in-10-years standard results in that reliability only if the reserve margin target is approximately met in all years. A capacity plan which has substantially higher reserves half of the time but substantially inadequate reserves the other half will not suffice.

Stated in another way, the target reserve margin to which utilities must plan is higher than the reserve margin required to meet a known load with known resources. At least as a first approximation, if the required reserve is 25 percent and the cumulative uncertainty in the future peak load for which resources are being planned is X percent over the minimum planning horizon, then the reserve for which a prudent utility must plan is 25 plus X percent. (Strictly speaking, the X percent load growth uncertainty should also be grossed up by the 25 percent reserve margin.)

Q. Can you use the example in Exhibit WHH-1 to demonstrate this point?

A. Yes. Exhibit WHH-2 shows the effects of a plus-or-minus 1 percent allowance for error around the load forecasts. Even with this modest margin of error, a utility which planned on the basis of meeting its reliability margin (that is, to add a new unit when required even though this results in excess capacity in most years) would have insufficient capacity in seven out of 10 years if load growth were at the high end of the band. Conversely, if load growth were at the low end of the band, there would be excess capacity in every year. Indeed, in six of the 10 years, the amount of excess capacity would exceed the size of the most recently added unit. While this sounds deplorable it is, by construction, a reasonably anticipated outcome from a capacity plan which is, in fact, <u>inadequate</u> to meet the reliability requirement.

Q. What conclusions do you draw from this example?

A. Since a capacity plan designed only to achieve reliability requirements if expectations turn out to be correct will have inadequate capacity under prudently foreseen circumstances, any excess capacity standard should provide an incentive for -- at least not penalize -- planning which recognizes and makes allowance for such uncertainties. In other words, in applying the excess capacity standard, the Commission should take into account whether the circumstances during the construction period of the unit coming on line were such that the achieved reserve margin is due to imprudence in capacity planning or to a set of circumstances which resulted in load growth at the low end of a reasonably foreseen band. If the situation arises from the latter set of circumstances, and the Commission nevertheless wishes to shield current ratepayers from a portion of the costs of excess capacity, fair ratemaking requires a full deferred return on and of the investment. Otherwise, we would have a set of regulatory rules which, on average, penalize utilities for the prudent actions required to reasonably assure that they could meet their statutory requirement to serve.

To be more specific, a calculation of a fair allowed reserve margin under an excess capacity standard would require the Commission to first determine the minimum reserve margin required for reliability purposes. That reserve margin should then be adjusted upward to the extent that the Commission determines that a prudent utility should have planned its unit additions based on peak loads which are higher than materialized. This adjusted reserve margin should then be compared to capacity available without the new unit. If that capacity is deficient, then a portion of the new unit is needed and (due to a recognition of the lumpiness problem) all of the unit is therefore needed.

Q. You have indicated that if utilities plan capacity on the basis of barely meeting target minimum reliability levels that there is a serious risk that target reliability will not be achieved. Do most utilities in fact plan on the basis of higher planning reserve margins to compensate for the risk of underforecasting loads?

A. Not explicitly. However, utility managers have long been aware of this problem and, I believe, the conservative nature of the slow reductions in load forecasts through the 1970s and early 1980s was, in part, motivated by an awareness of the risk of load forecast error. The example in Exhibit WHH-2 demonstrates that if the load forecast risk is symmetric, capacity plans based on minimum reserve criteria take serious risks with the requirement to serve. However, if load forecasts are conservatively high, this risk is substantially reduced.

The Irrelevance of Plant Cost
Comparisons and Life Cycle Evaluations

Q. Dr. Hieronymus, in your opinion, what, if any, relevance do comparisons of the cost of a particular nuclear plant to other "comparable" plants or the presence or absence of life cycle net benefits have to the application of the principles for ratebase determination which you have been discussing?

A. Neither issue, in my opinion, is of substantial relevance.

Q. Please explain your position as respects the relevance of nuclear plant cost comparisons to prudence and/or used and useful determinations?

A. Clearly, the relative cost of a unit neither proves nor disproves prudence: A unit could be relatively inexpensive albeit imprudent or expensive but still prudent due to circumstances beyond the utility's control and unrelated to the reasonableness of its decisions. Moreover, it could simply appear to be expensive due to the vagaries of the difficult task of making comparisons among units. At best, such comparisons can be useful as a frame of reference in determining whether any useful purpose might be served by initiating an inquiry into the prudence of construction management.

Clearly, a cost comparison is not relevant to an excess capacity determination and, in my view, a showing that a plant's cost turned out to be above average would be similarly irrelevant to a determination that the plant was not used and useful under any other definition of that standard.

Q. Why do you believe that the presence or absence of life cycle net cost has no substantial relevance to either principle?

A. As I have described above, I believe that the prudence standard must be given primacy in ratebase determinations as compared to the excess capacity standard. A life cycle cost benefit study made contemporaneously with the request for ratebase inclusion of a plant is not relevant to application of the prudence standard. Indeed, it is directly in conflict with the standard. I have indicated that application of the prudence standard involves the evaluation of decisions or actions based upon the known or knowable information at the time a decision must be made or action taken. Reliance upon hindsight, i.e., a knowledge of the results obtained from such decision or action, which knowledge was not available at the time such decision was made or action was taken, is not permissible. Reliance upon a life cycle cost-benefit study performed after the plant is completed and based upon the knowledge available at that time to evaluate prudence, or as a component of the used and useful standard, seriously violates the proscription against the use of hindsight.

Q. How does a life cycle cost-benefit analysis violate the proscription against hindsight?

A. The question answered by such a study is, will Limerick pay for itself based on a study conducted in 1985 and based on 1985 data and forecasts? Consider how one would conduct such an economic analysis. The cost of Limerick used would be the after-the-fact cost of the plant, not the cost expected at some earlier time. Fuel savings, O&M costs, replacement plant costs, capacity factors, and so forth, are all current estimates based on recent data not available during the years in which decisions were made. The timing of need for replacement capacity in an optimized alternative scenario would be based on a 1985 load forecast. This analysis -- but for its lavish use of hindsight -- is precisely the type of analysis which one would have used in 1974 or earlier to assess whether PECO should build Limerick. Indeed, the economic test is nothing more or less than a test of whether it was prudent to decide initially to build Limerick Unit No. 1, completely and deliberately without any restraints on hindsight.

Second, employment of such a study, whether under the prudence or used and useful rubric, as a determinant of ratebase inclusion violates the precepts of fairness which I described earlier. Specifically, I have argued that fairness in ratemaking requires that regulatory standards not be changed after investments have been made so as to eliminate the reward which motivated the investment. Implicit in the idea that a life cycle economic analysis is relevant either under the rubric of the prudent investment standard or the used and useful standard is the notion that whether a plant can be forecasted confidently to provide net benefits is an additional criterion for ratebase inclusion. To my knowledge, no such standard has ever existed in Pennsylvania or elsewhere, as I shall discuss briefly below.

Third, employment of such a study to value that amount of a new plant included in ratebase constitutes selective, and therefore, unfair "fair value" ratemaking. Essentially, it applies different ratebase valuation rules to utility assets dependent upon whether they are cost-beneficial, i.e., limiting highly successful investments to their actual cost (and not their greater value to the ratepayer) while valuing less successful investments to less than their actual cost (that being their perceived value to the ratepayer). For example, PECO has a number of plants which cost far less than any hypothetical replacement which could be built beginning today. These plants are "worth" far more than current book value on the economic benefit method of valuation. Under any true version of fair value ratemaking, these plants would be valued at much more than historic cost less depreciation. The nonuniform application of fair value for purportedly uneconomic plants and historic cost for economic plants would value plants at the "lesser of cost or market," a guarantee that utility investments will earn a fair return only under conditions of substantially perfect foresight.

Q. Would the adoption of such a regulatory standard create disincentives to proper, cost-minimizing investment decisions by utilities?

A. Yes, it would. Under this type of regulation, a utility planning capacity is told, "Go ahead. If you survive an extended period of mostly noncash earnings and the need to raise extensive capital with little choice as to timing (making nearly certain at least some dilution in book value), you win a chance to compete in an in-service ratecase. There you will get a chance to prove that your investment was not imprudent and that the capacity is needed. If you succeed, then you get a further chance to demonstrate that your plant is cheaper than a hypothetical optimum alternative developed after 10 or more years of new information on load growth, plant costs, and new government regulations. If you fail this test, you lose everything not needed for bare survival of the company. Now here is your big prize for entering this dangerous game: if you win, you get your money back."

No investor would invest in a mutual fund in which he gets the dividends, but must absorb any capital losses and keep none of the capital gains. That is what a utility investor would be required to do under "lesser of market or book" regulation. Unless the Commission were to allow equity returns high enough to entice investors to enter this unfair game, the utility would be unable to raise funds for new investment, even if it were foolish enough to want to do so.

Unfortunately for the utility, it has no option but to invest, since it must meet its legal requirement to serve. How will the prudent utility invest under these circumstances? First, it will minimize investment.

This means both minimizing the size of capacity additions by taking greater risks with reliability and choosing a resource mix which minimizes investment cost per kilowatt. This strategy minimizes the amount which must be put at risk. Second, it will select minimum lead time resources since shorter lead times reduce the chances that unanticipated events will change the optimum level and mix of resources by the time that the decision is second-guessed.

Neither of these concerns, i.e., either minimizing investments or selecting short lead time investments to avoid the risk of an "economic value" adjustment (or an excess capacity adjustment for that matter) is consistent with the proper goals of utility planning: cost minimization or meeting the requirement to serve. Logically, forcing the utility to concern itself with these additional criteria can be relevant only if the decisions it would make are different than its decisions were it concerned only with service reliability and cost minimization. It necessarily follows that the consequence of an economic test for ratebase inclusion upon utilities, if applied prospectively, will be to disadvantage ratepayers.

Q. Is the propriety of the "economic valuation" prerequisite altered if it is applied under the used and useful principle rather than the prudence principle?

A. No, its adoption is improper for all of the reasons I have described above regardless under what rubric its application is sought.

Q. You stated that a separate test of net benefit is unprecedented and hence was not reasonably anticipated by PECO's investors when they advanced the funds necessary for Limerick construction. Has application of such a prerequisite been uniformly rejected by regulators?

A. Yes, it has been rejected for the reasons I have discussed as well on the additional grounds of unpracticality. For example, the Illinois Commerce Commission in its decision on the Callaway nuclear plant wrote:

> In conclusion, the Commission is not persuaded by arguments which are based primarily on the purported current availability of lower cost alternatives to Callaway. The determination of the most economical capacity alternative should be evaluated in the time frame when the capacity was planned, not in a hindsight analysis of a plant which is already in operation. (Order, Case No. 85-0006, pp. 21-22).

The Montana Commission's Colstrip 3 decision initially did accept an economic standard. However, that decision was overturned and the Commission elected to not appeal the Court's findings which stated:

> The Commission has not been empowered by the legislature to act as "surrogate for the marketplace" and to displace, without any finding of imprudence, unreasonableness, or need, the generation resource acquisitions made by a utility.
>
> The Commission's marketplace standard was unreasonable, arbitrary, and clearly erroneous, because it used the supposed market value of electricity only to reduce the value of the output of the Colstrip 3 generating station, and it did not use the same supposed market value to increase the value of the output of the older generating facilities on the MPC system, such as its hydroelectric facilities (Judgment, Cause No. 84-C-388, District Court for the Second Judicial District, p. 7).

Finally, in the recent Susquehanna 2 ratecase, ALJ Christianson spoke to the practicality of basing current ratemaking decisions on the long-range forecasts which necessarily underlie economic cost/benefit studies:

> I have <u>not</u> found the various long range projections to be very helpful. The many variables, including oil prices, interest rates, maintenance expenses and capacity factors, produce a great degree of uncertainty. Difficult comparisons tend to magnify variability. My inclination is to disregard all of these "benefit/detriment" presentations as speculative.... I have little use for long range economic forecasts. (Docket No. R-842651, Recommended Decision, pp. 50 and 53. Emphasis in original.)

Q. Dr. Hieronymus, you have testified at some length that the economic benefit or lack thereof from Limerick is irrelevant to the regulatory treatment of the plant under proper standards. Do you nonetheless have an opinion as to whether the unit will pay for itself?

A. Yes. At my request and under my direction, PECO has prepared a life cycle analysis which compares PECO's revenue requirements in a case in which Limerick does not exist to a case in which Limerick and 50 percent of common is ratebased and Limerick is available to meet PECO's loads. This analysis is based on PECO's standard corporate assumptions which I have reviewed and found to be reasonable.

This study shows that on a life cycle basis, the expected net present value of Limerick Unit No. 1 is a positive 2.0 to 2.8 billion dollars. Where it will fall in this range depends on the availability of purchased power from west of PJM. If acid rain legislation is imposed or if any ECAR units on which construction is not currently proceeding are cancelled, or if ECAR loads grow at a rate higher than the current forecast it will be at the high end of the range. If none of these three events occur, it is likely to be at the lower end of the range.

It is important to recognize that these calculations assume that PJM would be willing, over a period of decades, to supply PECO with large amounts of energy on a split savings basis while charging it for capacity only at the carrying cost of a peaker. I view it as quite unlikely that the other PJM companies would tolerate this abuse of the interchange for long. To test the effects of a revision to the PJM pricing agreement, I have examined revenue requirements on the assumption that the PJM capacity charge would be increased by 50 or 100 percent. I found that this would add $0.6 billion to $1.2 billion to the net present value of Limerick Unit No. 1.

<u>Limerick Schedule Relative to Comparable Plants</u>

Q. You stated in your summary of testimony that you had also assessed the construction schedule of Limerick Unit No. 1 relative to that of other units. What is the relevance of this analysis to issues which you believe should govern the ratebase treatment of Limerick?

A. It has the same questionable relevance as would a comparison of the cost of Limerick to other plants. Neither prudence nor imprudence can be affirmed based on whether the schedule turned out to be long or short. At best, an inordinately long or short schedule would tend to suggest imprudence or prudence, respectively. However, the after-the-fact schedule length clearly cannot establish whether PECO's decisions were prudent or not. Nevertheless, I have made the comparison, basically because I am aware that is has been argued in previous proceedings that PECO imprudently delayed completion of Limerick.

Q. Please explain your analysis of the schedule for Limerick Unit No. 1.

A. I note first that, despite the problems which developed with the pumping station and challenges to the evacuation plan, the currently anticipated period between issuance of the Limerick construction permit and commercial operation, 11.7 years, is only 4 months longer than the average for plants scheduled to come on line in a period within plus or minus two years of Limerick Unit No. 1's commercial operation date. Hence, there is no prima facie case that the schedule was unduly long due to below average management competence or for any other reason.

Of course, such raw comparisons are not fully valid. For example, larger plants can be anticipated to take longer to construct than smaller plants. Hence, I have used regression analysis to develop "predictions" of plant schedules based on the characteristics of the plant. If the scheduled length as "predicted" by a regression developed using data on a comparable group of plants, then the schedule cannot be said to be unduly or unreasonably long.

Q. To what set of plants did you compare the schedule of Limerick Unit No. 1?

A. I have compared it to two overlapping samples of plants. The first consists of all units which have come on line or are scheduled to come on line within plus or minus two years of the February 1986 estimated Limerick Unit

No. 1 commercial operation date. The second sample is all noncancelled plants which received their construction permits within two years of the June 1974 construction permit date for Limerick.

Q. Why did you choose these two samples?

A. The first of the two samples was chosen on the basis that these plants are in the same cohort as Limerick. Since the time required to construct nuclear plants has risen greatly over time, selecting the sample based on time of completion is a reasonable first cut at a comparable population. My second comparative group was chosen because I anticipate the assertion in this proceeding that Limerick's schedule was overly long and hence it belongs in a cohort centered around some earlier date. If it turns out that Limerick's schedule is typical for plants begun contemporaneously with it, then this assertion would be without foundation.

Q. How did you adjust the schedule of the other plants to be comparable to Limerick?

A. I employed ordinary least squares regression techniques. Basically, the regression determines the relationship between each of the various variables thought to be related to schedule (e.g., size, whether the plant is in the Northeast, and so forth) and schedule length. Based on these average relationships, the schedule for each plant in the database is "predicted." That is, the regression "predicts" how long the plant "should" have taken to construct based on its specific characteristics and the average relationship relating such characteristics to schedule duration.

Q. How did you select the characteristics used to predict the schedule duration of the plant?

A. I first built a database consisting of the characteristic of the plants or of the environment in which they were built which I could measure. I then used a technique called stepwise regression to pick the characteristics for which the relationship with schedule was statistically meaningful. This technique, which lets the computer do the choosing, was used to quiet potential assertions of bias in selecting the predictive characteristics. Of the roughly 30 characteristics in the database, only 10 or so turned out to pass the statistical test which I used.

Q. What do your regression analyses show?

A. The regression analysis for schedule, shown in Exhibit WHH-3, indicates that large plants, plants in the Mid-Atlantic region, plants for which the utility served as its own Architect-Engineer, and (unsurprisingly) plants with numerous delays in fuel load date relative to original expectations took longer to construct, while plants built by experienced Architect-Engineers, plants with cooling towers rather than open-cycle cooling, and (surprisingly) plants in rainy areas took somewhat less time to construct than average. Exhibit WHH-4 shows that on an adjusted basis, Limerick was completed slightly more rapidly than would be anticipated.

Exhibit WHH-5 shows the regression results for plants started in the same timeframe as Limerick. Note that while the equation is similar, its predictive power is notably weaker. This may reflect, in part, the fact that while many plants built to be completed in the

1984-1988 period have been deliberately delayed due to reduced load growth or other reasons, a few of the plants started in 1972-1976 have been delayed by much more substantial amounts. Also, the poorer "fit" of the equation reflects the fact that a few of these plants were essentially complete prior to the TMI accident and were built on shorter schedules than could be achieved subsequently. Overall, as Exhibit WHH-6 illustrates, Limerick Unit No. 1 is, again, built slightly faster than one would expect based on its characteristics.

Q. What do you conclude from this analysis of the Limerick Unit No. 1 schedule?

A. The Limerick period of construction is typical for plants of its vintage irrespective of whether it is compared on an adjusted or unadjusted basis and irrespective of whether it is compared to plants which were started or completed in the same general time period. These results do not support the hypothesis that Limerick construction was unreasonably long due to imprudent construction management or system planning decisions.

Schedule Effects of the 1974, 1976, and 1978 Delays in Commercial Operation

Q. You have testified that the Limerick Unit No. 1 schedule was in fact typical for plants receiving their construction permits at that time. Are you aware that Limerick experienced three very substantial slippages in the announced schedule in 1974, 1976, and 1978?

A. Yes, I am.

Q. How can you square your conclusion that the schedule performance was typical with these large early slippages in schedule?

A. First, many other units also experienced major slippages over this period. Second, and more importantly, PECO's early slippages in announced schedule allowed it to maintain that schedule to a far greater degree than did other utilities.

Q. Can you demonstrate this superior schedule performance?

A. Yes. Exhibit WHH-7 shows the slippages in announced schedules for nuclear plants under construction in the post-TMI period. Over this six and one-half year period, the typical plant schedule was slipped by approximately three years. Only 15 of the 54 units slipped by less than two years and only two units slipped by less than one year. One of these two units was Limerick Unit No. 1. I should note that the Spring, 1979 commercial operation date estimates upon which these calculations are based were compiled contemporaneously by the Tennessee Valley Authority.

Q. Why was PECO more successful than other utilities in maintaining its construction schedule after the 1978 announcement?

A. I cannot speak to the construction management practices which may have contributed to this performance. However, two factors are apparent from the data. First, the publically announced slippages in schedule for Limerick Unit No. 1 in 1976 and 1978 were substantially longer than the slippages in the construction schedule to which the project was managed. Second, while the construction schedule for Limerick did slip subsequent to 1978, PECO was more successful than the typical utility in completing construction on schedule. Indeed, even taking into account the pre-TMI slippages, PECO's schedule delay performance was slightly better than average and the rapidity with which it recognized events likely to stretch schedules appears to have been better than average.

Q. Can you demonstrate these points?

A. Yes. Exhibit WHH-8, which is based on Nuclear Regulatory Commission data, shows the total delay in fuel load date after issuance of the construction permit for all plants which have loaded fuel in the post-TMI period. Despite the fact that Limerick No. 1 is one of the latest plants to load fuel, and hence was exposed to the post-TMI regulatory environment for a substantially longer period than the average plant in this database, its overall delay performance was slightly above average.

Exhibit WHH-9 compares the evolution of the Limerick Unit No. 1 construction schedule in comparison to other plants started in the 1972-1976 period. At each stage of construction, the Limerick forecast was more accurate than the average. After the 1974 delay, the Limerick total schedule estimate was 72 percent of what turned out to occur. At the same stage of construction, the average plant's forecast was only 58 percent of actual. After the 1976 delay in the construction schedule, the Limerick forecast improved to 86 percent of actual. The average plant was still forecasting a schedule which was 36 percent shorter than actual. By 1981, four years before fuel loading, the Limerick forecast was exactly correct. The average plant was still underforecasting the total schedule by 15 percent and, obviously, the time required to complete the plant by a much greater percentage. It is important to note that Exhibit WHH-9 assumes that all of these plants -- many of which have not yet loaded fuel -- will meet their most recently announced fuel load dates. In the likely event that some of these plants will encounter further slippages, the degree of superiority of PECO's schedule forecasting/schedule attainment performance is understated.

The Prudence of Limerick-Related
<u>System Planning in the 1975-1980 Period</u>

Q. What is the purpose of this section of your testimony?

A. I have testified that, at least in my opinion, the sole issue relevant to the recovery of Limerick Unit No. 1 cost by PECO's investors is the prudence of PECO's decisionmaking as it affected or might have affected the cost of meeting the needs of its customers. Other witnesses are testifying to various aspects of the prudence issue, including, especially, the prudence of construction management As a utility economist, my expertise is more limited. I shall address four issues:

- Were the peak load forecasts upon which PECO based its projection of the need for Limerick Unit No. 1 reasonable when viewed in the light of contemporaneously available information?

- Did PECO address the issue of whether completion of Limerick was a least-cost means of supplying the needs of its customers on a timely basis?

- Were PECO's studies methodologically sound and, to the extent that they were not, were methodological errors likely to have so biased the analyses that PECO improperly failed to conclude that Limerick should not be complete?

- Were PECO's assumptions and forecasts concerning key parameters affecting the costs and benefits of Limerick completion and its decisions to continue constructing Limerick reasonable when compared to the information which was then "known or knowable"?

Q. What is the basic methodology which you have followed in your analysis?

A. I first collected from PECO the available information on its peak load forecasts, Limerick cost/benefit studies, and assumptions bearing on Limerick costs and benefits which were current during the period of Limerick construction. Second, I and my staff have extensively collected and reviewed contemporaneous studies and assumptions which were or could have been available to PECO from outside sources. I then compared the PECO and non-PECO forecasts, studies, and assumptions to determine whether PECO's assumptions and conclusions were generally consistent with this external information. It is my belief that if PECO's assumptions and conclusions were generally consistent with the then-available consensus of opinion, then its studies and the decisions consistent with those studies were reasonable and prudent.

Q. What period of time does your analysis cover?

A. While I have collected and to some degree examined information over the entire period of Limerick construction, I have focused on the 1975 to 1980 period.

Q. Why have you focused on that period?

A. I view it as quite unlikely that anyone will seriously challenge PECO's belief in the late 1960s or early 1970s that substantial new baseload capacity would be needed or that constructing Limerick was a reasonable way of meeting that need.

With respect to the 1980 cut-off, I note that in I-80100841 the issue of Limerick completion was fully explored and, in 1982, PECO was told to complete Limerick Unit No. 1. Moreover, in my view the extent of Limerick Unit No. 1 completion by 1982 made cancellation so clearly uneconomic that I do not believe that continuing the completion/abandonment review into this period is necessary.

The Reasonableness of PECO's Past Peak Load Forecasts

Q. Have you compared Philadelphia Electric's past peak load forecasts to other such forecasts made at the same time?

A. Yes. The PECO forecasts show a pattern which is quite consistent with those of other utilities and such non-utility forecasters as the U.S. Department of Energy. In every year through 1982, peak load forecasts were consistently overstated, relative to subsequent developments and hence have been revised downward for virtually every utility and reliability council as well as for the United States as a whole. Exhibit WHH-10 compares PECO's load forecasts to two nonutility organizations, McGraw-Hill (as published in Electric World) and the U.S. Department of Energy, and to two compilations of utility forecasts, NERC, comprised of essentially all

United States utilities, and MAAC, the reliability region in which PECO is located. While PECO's forecasts also have been revised steadily downward, they are consistent with contemporaneous regional and national forecasts.

PECO's forecasts are within the range bounded by Electric World, NERC, and DOE in 1974 and 1975, and lower than the reference forecasts in each year after 1975. On a regional basis, PECO's forecasts were roughly equivalent to MAAC's forecasts over the period 1974 to 1977; after 1977, they were consistently lower.

Q. Can you also compare PECO's forecasts to those of other Pennsylvania utilities?

A. Yes. Exhibit WHH-11 compares PECO's 10-year load forecasts to six other Pennsylvania utilities. PECO's forecasts are on average slightly higher than the comparable composite forecast of these companies (though within the range of the individual companies' forecasts) in the earlier years -- 1972-1976, but beginning in 1978 and continuing through 1982, they have been well below this composite. I should note that year-to-year variations should not be considered important. The starting point for each forecast is the previous year's actual peak. If the actual peak was based on severe weather, the forecast growth rate will be understated. If based on mild weather, it will be overstated.

Q. Does the fact that PECO, DOE, and other utilities continuously revised their peak forecasts downward represent any methodological deficiency?

A. No. The very fact that several independent forecasters, using a wide range of forecasting techniques, continually readjusted their forecasts in a similar fashion, leads me to conclude that most forecasting errors experienced over this time period were not unique to a particular forecasting methodology.

Q. If methodology is not the core of the problem, what is?

A. No set of forecasting mechanics provides a crystal ball for the future. Even structurally perfect energy and peak load forecasting models (whatever that might mean) would have shown the general pattern displayed by the PECO forecast. Quite simply, the history of load forecasting since 1970 or so has been a history of disappointments due primarily to matters outside the control or primary expertise of the utility load forecaster and concerning which the experts in those areas have also forecasted badly.

Q. To what disappointments are you referring?

A. The primary one is the performance of the United States economy. The second has been the increases in the price of energy.

Q. Can you briefly describe the events which, in your view, led to this poor forecast performance?

A. The 1960s were a period of vigorous, though not unprecedented, growth in the United States economy. Real GNP from 1960 to 1969 grew by 4.4 percent per year. Real electricity prices fell, both in absolute terms and relative to the price of other fuels. These were the factors underlying the 7 to 8 percent electric growth in the 1960s.

In 1969, the United States entered the decade of stagflation. Real GNP growth fell to 3.1 percent. However, this figure masks far larger declines in real income per household and in real wages. In the 1960s, median income per household grew at nearly 3.5 percent per year in constant dollars. Over the next decade, growth averaged less than 0.5 percent. Average real weekly earnings actually fell over the decade.

Overlaying this deplorable economic performance were the energy price shocks of 1973-1975 and 1979-1980. Led by imported oil, these price increases soon infected energy markets generally. While the price of electricity fell somewhat relative to other fuels, fuels switching did not compensate for price-induced conservation.

Load growth was eroding due to a poor economy and rising energy prices. Yet no one in 1970 or later was forecasting a decade of stagflation. Despite poor recent performance, the economy was supposed to improve, as it did sporadically. Similarly, before 1973 no one predicted the success of OPEC. Even after the embargo, the view of most experts was that the cartel would not hold together.

In short, a load forecaster in the early 1970s who based his forecasts on the assumptions which turned out to be true would have been laughed at, and properly so. As the decade progressed, forecasters gradually lowered their forecasts as the national "malaise," to use President Carter's term, took hold. Still, there was reason not to be too pessimistic. The economy would one day turn around. There was substantial pent-up demand in the baby boom generation for housing and consumer durables. Phased decontrol of natural gas would lock in a high share of the home heating market. So, while load forecasts continued to phase down, they, in my opinion quite reasonably, remained above the recent experience.

Q. You noted that using nonweather corrected data can mask year-to-year changes in peak load growth forecasts. Can you place PECO's actual weather normalized forecasts in context?

A. Yes. Exhibit WHH-11 compares the weather adjusted 10-year forecasts to the then-most-recent 10 years of history. Over the 1973 to 1980 period, the forecast was reduced in every year. Note that the same is true for other Pennsylvania utilities. Through 1977, the forecast was generally similar to or slightly above the historic growth rate. However, the decline in the forecast fully reflected the decline in the historic load growth rate as it developed. Over that period, the forecast peak load growth rate fell from 7.4 to 4.2 percent, a decline of 45 percent. This compares to a decline of 40 percent in the 10-year history. In comparison, the nonweather adjusted forecast for other Pennsylvania utilities fell by 26 percent; their historical load growth fell by 24 percent. Hence, over this period, the relative rate of decline in the peak load forecast was consistent with the decline in historic load growth. The growth rate decline was substantially larger than that of other utilities in the state. However, if each is compared to its own history, the declines in growth rate forecasts are comparable.

Between 1977 and 1980, the PECO peak load forecast growth rate fell by an additional 62 percent. This can be compared to a further 45 percent decline in its historic growth rate. The state's other utilities lowered their forecasts by 41 percent, relative to a 42 percent decline in their historic growth rates.

Q. What conclusions do you draw from this analysis?

A. PECO reduced its forecasts somewhat more rapidly and substantially farther than did other Pennsylvania utilities, utilities generally, and well-known nonutility forecasters. The rapid and substantial decline in the load forecast fully reflected the below average relative load growth performance of the service territory as it unfolded through the 1970s. While PECO's forecasts over this period were high in retrospect, they were not higher than other utilities. Given that the shortfall in load growth below the forecast was a result of unprecedented and largely unanticipated circumstances, I do not believe that PECO reasonably could have reduced its forecast of capacity needs any more rapidly than it did. This is particularly true since, as I noted earlier in my testimony, PECO's capacity planning process made no explicit allowance for the possibility that its load growth would exceed the forecast.

Review of PECO's Limerick Cost-Benefit Studies over the 1975 to 1980 Period

Q. Did PECO continuously reexamine the economics of the Limerick station throughout the 1975 to 1980 period?

A. Yes. In fact, PECO studied the economics of Limerick continuously from at least the early 1970s. Prior to receiving the construction permit, Limerick was compared to a number of alternative methods of meeting power needs. Thereafter, PECO compared the generation costs of Limerick to both coal and oil baseload generation until about 1978; subsequently, Limerick was compared only to coal baseload generation.

Q. Was it appropriate for the Company to evaluate nuclear economics versus coal and oil, and subsequently only to coal, throughout the period of construction?

A. Yes. First, coal was widely recognized as the primary feasible alternative to nuclear power throughout this period. As a baseload generation source, oil was becoming recognized as uneconomic compared to coal and nuclear power, particularly after the 1973 OPEC embargo. Furthermore, the Powerplant and Industrial Fuels Use Act of 1978 effectively prohibited the use of oil as a new baseload generation source. Thus, the emphasis on coal versus nuclear economics is proper.

In principle, it might have been appropriate to compare Limerick to nonbaseload sources of power which would meet reliability needs. However, PECO's already substantial amount of peaking capacity made it apparent that all new capacity additions, at least through the early 1980s, should be baseload capacity. Under these circumstances, it is appropriate and sufficient to assess the economic cost-benefit of completing Limerick by comparison to an equivalent baseload coal unit.

Q. How frequently did PECO analyze the relative economics of coal versus nuclear power?

A. The economics of coal versus nuclear power were examined quite frequently. Throughout the period of interest PECO produced at least one study per year which examined the relative costs of power from Limerick versus a baseload coal plant. In addition, it had an ongoing series of studies which were comparisons of coal to "generic" (i.e., post-Limerick) nuclear plants. While I will focus only on the Limerick-specific studies, these other studies also illustrate a continued monitoring of the economic attractiveness of nuclear power relative to alternative forms of generation.

Q. What did these PECO studies show?

A. Exhibit WHH-12 shows the basic results of PECO's studies. Generally, the cost of power from Limerick was found to be approximately 1 cent per kWh cheaper than the cost of power from a coal plant, though the advantage drops temporarily to only 1.3 mills in 1978. Thus, throughout this period, these studies showed that Limerick was cost-effective relative to alternative sources of new generation capacity.

Q. In your opinion, were these studies methodologically sufficient to form a reliable basis for concluding that Limerick should be completed?

A. Given that the studies showed an advantage to completion, yes. However, the studies up through 1978 contained two severe methodological biases against Limerick, one of which also continued to affect the study results through 1980.

Q. What is the bias which affected the pre-1979 studies?

A. Basically, these studies are what are called "levelized cost" studies. Levelized cost analysis is a standard engineering-economics method of project valuation. Levelized costing computes the present value of the stream of revenue requirements associated with the plant, then computes the fixed annual payment which is equivalent to that present value. Since there is a one-to-one relationship between present value and levelized cost, levelized cost analysis is a quite proper substitute for present value analysis.

In its early Limerick cost comparisons, PECO's levelized cost of coal and nuclear power were composed of two elements: a levelized charge for capital-related costs (return, taxes, depreciation) and a levelized operating cost. The levelized capital charge was computed properly as the fixed charge equivalent to the life cycle levelized revenue requirement for Limerick and the comparison plants. Operating costs (fuel, O&M, and nuclear insurance) were not true levelized life cycle costs. Instead, PECO used the fuel cost and O&M expense forecast for the first year of operation of the plant.

Q. How does this create a bias against Limerick?

A. The advantage of nuclear plants relative to coal plants is in their lower annual operating cost savings. Over time, the amount of such savings grows very substantially due to inflation and real escalation of fuels costs. PECO's calculations, by holding operating costs at their first year value, effectively ignored this growth in operating savings over the life of the plant. Holding these costs at their first year value was equivalent to assuming that the real (constant dollar) operating savings from Limerick relative to a coal plant would decline at the rate of inflation. In fact, PECO's corporate fuels escalation assumptions at that time agreed with the general view that fuels prices would increase at above the rate of inflation. Rather than declining rapidly over time, the real production cost advantage of Limerick should have been shown to be increasing over time.

Q. When did PECO remove this methodological bias against Limerick?

A. It was corrected beginning in 1979. However, I should note that some of the post-1978 studies continued to contain a partial version of this same bias in that only the first 10 years of operating cost savings were included in the life cycle calculation. Of the studies over the 1975 to 1980 period, only the October, 1980 study is a true life cycle cost comparison.

Q. What is the other bias against Limerick which is contained in the PECO studies?

A. The second bias is that the studies compare the full cost of Limerick to the full cost of power from the coal plant. This is perfectly proper if the question one is asking is, will the cost of power from Limerick be cheaper than the cost of power from a coal plant? It is not, however, the proper way to analyze whether Limerick should be completed. The distinction is that the cost of completing Limerick is, once construction begins, less than the total cost of the unit. The difference between total cost and the cost to complete the plant is the revenue requirements associated with the sunk cost of the plant. Since sunk costs were substantial even in

1975 and grew rapidly throughout the period, this bias is significant.

Q. Had these biases not been present in PECO's 1975 to 1980 studies, would PECO have been more likely to conclude that it should cancel one or both Limerick units?

A. No. The biases uniformly caused the studies to understate the advantages of Limerick completion. Had the studies not contained these biases, Limerick completion would have been shown to be even more attractive. Hence, these biases could not be said to have contributed to a hypothetically imprudent decision to complete Limerick. I should also note that PECO may well have been aware of these biases. I have noted that the bias arising from assuming constant fuels prices was eliminated in 1979. This was the first study subsequent to the 1978 study which on its face had indicated that Limerick was little better than a breakeven against coal. This suggests that the change in methodology was motivated by a recognition that, given the small apparent savings from Limerick in the 1978 study, a more refined analysis was warranted. I should also note that at least one study during this period explicitly recognized that the failure to eliminate sunk cost revenue requirements from the analysis biased the study against Limerick completion.

Q. Have you attempted to recast PECO's studies on a consistent life cycle basis?

A. Yes, I have.

Q. Would you please explain briefly how you have done this?

A. Yes. I have used the data provided in PECO's studies to produce full lifecycle generation cost estimates for Limerick and a coal-fired alternative for each year in the 1975 to 1980 period. I have used the data in PECO's studies combined with PECO's corporate assumptions (for the years in which they are still available) to produce these estimates. Exhibit WHH-13 summarizes the results of my calculations. In addition, I have estimated the 1979 generation economics using then-recent capital cost data provided in Emil Kasum's testimony filed in R-79060865. Exhibit WHH-13 compares the alternatives on a full cost basis; Limerick costs are not adjusted to reflect the fact that the plant is partially complete.

Q. Could you briefly summarize the conclusions one may draw from Exhibit WHH-13?

A. Quite simply, this exhibit shows that even on a full cost basis, lifecycle economics favored Limerick completion under the assumptions made by PECO over this period. As might be expected, the life cycle savings of the nuclear plant were substantially greater than the "mixed first-year" estimates shown for the 1975-1978 studies in Exhibit WHH-12.

Q. Is it significant that the advantage accorded Limerick declines over time, as shown in Exhibit WHH-13?

A. It is true that the advantage tends to decline; especially in 1980 it was less than it was in 1975. Certainly nuclear economics were generally viewed as a much closer call in 1980 by most if not all analysts than they were in 1975.

It is important to remember two points, however. First, an advantage is just that: an advantage. Although by 1980 the advantage had declined significantly from of what it was thought to be in 1975, nuclear economics were still preferred and completion of the Limerick plant could be justified even ignoring the fact that a substantial portion of its costs were sunk. The second point is that all these studies are indeed full cost studies. Because by 1980 the sunk costs of Limerick were a substantial fraction of the forecasted full cost, all of these analyses are significantly biased <u>against</u> the true economics of the Limerick plant. Properly interpreted, these studies indicate that building Limerick according to its then-forecast cost and schedule would be cost-effective even if one had the luxury of deciding anew whether to start construction. Obviously, taking the substantial expenditures already made in the plant into account would only reinforce this conclusion.

Q. Why do the savings shown in Exhibit WHH-13 appear to drop so suddenly from 1979 to 1980?

A. The primary reasons are capital costs and discount rates. Between 1979 and 1980, the company's estimate of Limerick's completed cost rose by over 20 percent, while their estimate of the cost to build a hypothetical coal plant increased by only about 4 percent; this alone would have reduced the computed benefit of the Limerick station. In addition, the Company also began to forecast higher future costs of capital and discount rates in 1980. This acted to both reduce the value of the future fuel savings associated with Limerick as well as increase the annualized capital costs. Nevertheless, Limerick still shows a sizable advantage relative to the coal plant.

Q. Would you please describe in more detail how you obtained the lifecycle costs shown in Exhibit WHH-13?

A. Yes. For the 1975 through 1978 studies, I followed essentially the same procedures. Capital costs and fixed charge rates were obtained directly from the referenced PECO studies. First year O&M costs for all plants were also obtained from the studies; these were levelized at zero percent real escalation over the assumed 35 year plant lives. Nuclear insurance was likewise levelized at an assumed zero percent real escalation over the life of the plant. My general understanding is that this was consistent with PECO's expectations at that time.

First year fuel costs for coal plants were obtained from the PECO studies; escalation rates for 1978 and thereafter were obtained from the PECO corporate assumption book and held constant over the life of the plant. Since PECO was unable to locate its earlier corporate assumptions books, it was necessary to infer the fuels escalation rates from the Limerick studies. Coal escalation was calculated as the implied escalation rate from the then most recent fuel price data from PE's Eddystone and Cromby plants to the first year cost given in the study. This rate was also held constant through the life of the plant. First year nuclear fuel costs for 1978 were obtained from the corporate assumption book and escalated at the rate therein over the life of the plant. For earlier studies, the three most recent years of Peach Bottom fuel costs were all adjusted to constant dollars, averaged, and escalated at the escalation rate implied by the Limerick studies' first-year fuels cost over the life of the plant.

The 1979 lifecycle costs were estimated using capital cost values supplied by Emil Kasum of the Company in R-79060865. Fuels costs and escalation rates were obtained from the corporate assumption book for

1979. O&M expenses were computed by using the three most recent years of experience at Peach Bottom for nuclear O&M and the average of Eddystone and Cromby for coal plant O&M, escalating at the inflation rate to the in-service dates and levelizing at an assumed zero percent real escalation thereafter.

Inflation rates and discount rate assumptions for the 1978-1980 calculations were obtained from the corporate assumption books. Due to the unavailability of these assumption books prior to the 1978 issue, the 1978 assumptions for these rates were used for the 1975-1977 calculations. This assumption is consistent with PECO's use of a constant 16 percent fixed charge rate throughout the 1975 to 1978 period.

Q. You mentioned earlier that PECO's October 1980 study was the Company's first full life cycle study. Why have you chosen to adjust its results for presentation in Exhibit WHH-13?

A. I have done so in order to be consistent with the other studies I have examined. With respect to fuels, I note that the October 1980 study used an assumption for coal prices almost exactly equivalent to that in the corporate assumptions book, yet used a nuclear fuel price almost 50 percent higher. My calculation of O&M expenses based on escalating PECO's historical actual expenditures results in estimates three to four mills/kWh lower than the Company's estimates used in the October 1980 study for both the coal and nuclear units. Hence, changes in the O&M assumption do not greatly contribute to the calculated differential savings of Limerick.

Q. In your view, is there any significant likelihood that your life cycle cost studies differ in any important way from PECO's contemporaneous assumptions?

A. The only assumption which might differ materially is the life cycle escalation rate for fuels since PECO's corporate assumptions only cover the first 10 years. To test the robustness of my results, I evaluated the levelized generating costs under the assumption of real escalation only to a point in time 10 years from the date of the study, followed by constant zero percent real escalation for the life of the plant. In each case, the basic result of the analysis was unchanged: Limerick remained preferred to the hypothetical coal alternative.

Q. You have stated that because all of these studies consider the full cost of Limerick, they are biased against the true economics of the Limerick plant. Have you attempted to restate the results of these life cycle studies on a "to go" basis?

A. Yes. I have estimated Limerick sunk cost at the time each study was performed and removed their associated revenue requirements from the Limerick cost estimate. The resulting "to go" generation economics are shown in Exhibit WHH-14. As this exhibit shows, on a "to go" basis, Limerick's advantages over a hypothetical coal plant are actually approximately constant throughout the period of the studies. This exhibit also demonstrates that even by 1980, the true economics of the Limerick station were not a "close call" at all; Limerick retained a substantial advantage (almost six cents per kilowatt-hour) over the alternative generation choice.

Q. You mentioned earlier that during this time period, the prevailing belief among utility and nonutility analysts was that nuclear power would be cheaper than coal-fired power as a baseload energy source. Would you please elaborate on this point?

A. I have surveyed much of the literature which dealt with nuclear versus coal generation economics published during this period. I believe it is fair to state that the preponderance of published data and analyses favored nuclear energy in this period. In Exhibit WHH-15, I have summarized many published sources which evaluated comparative generation economics; Exhibit WHH-16 lists references I have used here and subsequently in discussing PECO's studies. All of the studies shown in Exhibit WHH-15 indicate economic preference for nuclear power as opposed to coal power. Toward the end of the decade, some analysts began to indicate that coal might be preferred to nuclear in some locations, usually western states in which inexpensive stripmined low-sulfur coal was available. Nevertheless, nuclear remained the preferred alternative, particularly in the Northeast.

Q. Did the United States government take a consistent position throughout this period with respect to the economics of nuclear generation?

A. Certainly those agencies one would expect to be most concerned with nuclear economics did. Although I can find no single "official" United States government estimate of nuclear generation economics during this period, the Department of Energy's Energy Information Administration did regularly evaluate baseload electric generation economics. In their annual reports to Congress throughout this period, the EIA consistently indicated that nuclear power was economically preferred to coal. Indeed, in using EIA's mid- and long-term models of the United States energy economy, nuclear power consistently had to be constrained as an energy source because if the models were free to optimize the type of new capacity based on economics alone, nuclear power would dominate to an implausible degree.

Another government source during this period is the series of cost studies made for the NRC (earlier the AEC). The 1979 study included a comprehensive estimate of total generating costs for nuclear and coal plants under a variety of circumstances. The study showed consistent and significant advantages to nuclear generation economics.

Q. What do you infer from this review of these studies?

A. These studies demonstrate that the prevailing sentiment in the mainstream energy economics literature during this period was that nuclear power was a reasonable and proper choice for new generating capacity in the 1980s and beyond. These were the sorts of documents which were available to influence and guide generation planners of electric utilities at this time. Certainly PECO's estimates of nuclear versus coal generation economics were generally consistent with the consensus of the contemporaneous literature. Given that the consensus belief was that nuclear power was an appropriate choice for newly started baseload capacity, PECO's conclusion that it would pay to complete a plant which was already under construction can hardly be regarded as aberrant or imprudent.

Q. Have you also examined the individual assumptions made by PECO in their generation economics studies?

A. Yes. I have examined PECO's assumptions in their studies, in particular, their assumptions of nuclear and coal capital costs, capacity factors, operations and maintenance expenses, and fuels escalation rates. In each of these areas, I have identified the assumptions used in the PECO studies and the assumptions which appeared in the literature at the time. Then, where possible, I have placed these two sets of assumptions on a comparable basis so that PECO's position relative to the "mainstream" may be easily seen.

Q. Turning first to nuclear capital costs, how do PECO's estimates of nuclear capital costs used in these studies compare to those found in other sources?

A. I find that PECO's estimates of nuclear capital costs used in their studies were generally in the mainstream or slightly higher than contemporaneous nuclear capital cost estimates. On this basis, I conclude that PECO cannot be faulted for basing its decisions to continue Limerick construction on unreasonably low forecasts of its costs. While PECO's forecasts -- like those of every other utility and virtually every nonutility forecaster turned out to be too low, PECO's forecasts were if anything, high by contemporaneous standards.

Q. Would you please describe how you reach this conclusion?

A. Yes. First, I have identified in Exhibit WHH-17 the nuclear capital costs per kilowatt used by PECO in its various Limerick economics studies throughout the 1975-1980 period. In Exhibit WHH-18, I have summarized estimates of nuclear capital costs from various sources published between 1975 and 1981. Once again, these sources have been identified in Exhibit WHH-16.

The first two references I have noted in Exhibit WHH-18, an AEC WASH report (a predecessor of the EEDB series) and an EPA study, compare plants with in-service dates quite close to PECO's anticipated Limerick in-service date in PECO's 14 November 1975 study. However, where PECO was forecasting almost $950/kw for Limerick at this time, these studies were generally in the $700/kw range.

In early 1976, the FEA published an estimate of $500-550/kw (in 1975 dollars) for a 1982 plant. If one assumed 6 percent inflation through 1982, this would equate to $750-815/kw in as-spent dollars. In October of 1976, PECO forecast a Limerick cost of $1,201/kw, substantially higher than the FEA value, and almost equal to what Leonard Reichle of EBASCO estimated in

December 1976 for a station to be completed as late as 1987-1989. Again, PECO appears to be somewhat high compared to the literature.

PECO's 1977 estimate for Limerick was also on the high side of Gibbs & Hill's April 1977 estimate for a 1987 plant. The October 1977 estimate published in Science is probably a bit higher than PECO's 1977 estimate in nominal terms, but is appropriate for a plant to be completed one to three years after the then-anticipated Limerick completion date.

From 1978 forward, I have available PECO's corporate assumptions regarding construction cost escalation and inflation. I have used these to adjust the published estimates shown in Exhibit WHH-18 to Limerick's then-anticipated in-service date. I have used PECO's 1978 assumptions to adjust studies published over the year preceding the issuance of the 1978 assumptions, PECO's 1979 assumptions to adjust the studies of the year previous to that, and so on. The results of these adjustments are shown in the "adjusted" columns of Exhibit WHH-18. I have summarized these adjusted values and the comparable PECO assumptions in Exhibit WHH-19.

Q. What does Exhibit WHH-19 show?

A. This exhibit shows that from 1978 forward, as in the earlier years, PECO was certainly within the mainstream of published forecasts for nuclear capital costs. If anything, PECO was higher than average in general and thus conservative relative to other forecasters.

Q. In addition to comparing PECO's nuclear capital cost estimates to the published sources you have surveyed, have you also compared PECO's estimates to contemporaneous estimates of other electric utilities?

A. Yes. I have examined data from two sources -- the utilities' annual FERC Form 1's and the TVA reports on construction costs -- and compared PECO's capital cost estimates at different times to contemporaneous cost estimates made by other utilities for plants then thought to be completed at or near Limerick's then anticipated completion date.

Exhibit WHH-20 summarizes this analysis. In this exhibit, I list five different observations of Limerick station costs obtained either from FERC Form 1's or TVA reports. Limerick's reported costs shown here differ somewhat from some of the studies due to differences in data sources, timing, and so on. For each of these observations, I have gathered all the contemporaneous estimates of other utilities for two-unit plants (or stations) to be completed within one year of the then-anticipated Limerick completion date. The date for both Limerick and the other two-unit stations used is the mean completion date of both units. As this exhibit shows, PECO was consistently forecasting higher completion costs for Limerick than the average for other utilities building multiple unit stations for the same completion data. This reinforces my belief that PECO was more realistic about nuclear capital costs than were many other analysts during this period.

Q. Turning now from nuclear capital costs to coal plant capital costs, would you please summarize your findings regarding PECO's estimates?

A. Yes. PECO's coal plant cost estimates were generally consistent with other published estimates, being perhaps somewhat high early in the period of interest and somewhat low from 1978 forward.

Q. Would you please describe your analysis of this?

A. Yes. First, I have summarized the coal plant capital costs and in-service dates used in the PECO studies in Exhibit WHH-21. Exhibit WHH-22 summarizes estimates of coal plant costs obtained from generally the same sources as Exhibit WHH-18. As with my comparison of nuclear capital costs, I am able to place the published estimates on a comparable basis to PECO's, starting in late 1977. I have summarized the results of this comparison in Exhibit WHH-23.

It is somewhat difficult to compare PECO's estimates for 1975, 1976, and 1977 to published sources due primarily to differences in in-service dates. PECO's 1975 estimate is somewhat higher than the WASH-1345 estimate ($625/kw) or the TBS estimates for the EPA ($415-520/kw) for plants completed at comparable times. However, neither of these published sources are explicit about including scrubbers on their coal plants, which was generally explicitly stated if included in estimates made prior to 1979 or so. The PECO estimate of November 1975 is almost exactly equal to the February 1976 FEA estimate for a scrubbed coal plant if one assumes 6 percent expected inflation between 1975 and 1982.

In late 1976, PECO increased its estimate to $910/kw, higher than the FEA estimate of February of that year, but close to Leonard Reichle's December estimate adjusted for an assumed 6 percent expected inflation. The Gibbs & Hill estimate of April 1977 is also roughly consistent with PECO's 1976 and 1977 estimates, adjusting for in-service date differences at an assumed 6 percent expected inflation.

PECO's 1978, 1979, and 1980 estimates are lower than average when compared to other estimates when placed on a comparable basis. As Exhibit WHH-23 shows, PECO's estimates are within the range of other published estimates (except for 1979, when it is clearly low) but below the average of the published estimates.

Q. What would these low coal plant capital cost estimates imply?

A. These relatively low coal capital cost estimates had the effect of making PECO's forecast of the relative savings from Limerick completion lower than the forecast it would have made based on a more typical estimate. Thus, like PECO's relatively high nuclear plant cost estimates, these estimates contributed to the conservatism of PECO's studies and the robustness of PECO's conclusions favoring nuclear power economics.

Q. Considering capacity factors next, how did PECO's assumptions compare to those being made in the literature?

A. In the studies I have examined closely, PECO consistently used a 70 percent capacity factor assumption for both nuclear and coal plants. I find that this was not an uncommonly high value to use during this time, nor was it uncommon to assume equal capacity factors for coal and nuclear units.

Q. Can you compare this assumption to those made in the literature?

A. This comparison is even more straightforward than my comparison of capital costs. In Exhibit WHH-24, I have summarized the capacity factor assumptions I have obtained from published sources. Forecasts of 70 percent (or higher) were quite common for both coal and nuclear units. More often than not, capacity factors were assumed to be equal for coal and nuclear plants in these studies. In cases where unequal capacity factors were assumed, it is more often than not the nuclear plant which is accorded the higher capacity factor.

Q. How would you describe PECO's operations and maintenance expense estimates?

A. I have found that where I am able to make comparisons, PECO has generally employed a somewhat higher than average nuclear O&M and a somewhat lower than average coal O&M. The effect of this is to further increase the conservatism present in the PECO studies.

Q. Would you please describe your analysis of O&M assumptions?

A. Yes. First, I have summarized the first-year O&M values used in the referenced PECO studies. This appears on Exhibit WHH-25. The data on O&M expense in the literature is somewhat sparser than the data on capital cost or capacity factors. Exhibit WHH-26 summarizes estimates of coal and nuclear O&M expense obtained from published studies. In Exhibit WHH-27, I compare the published data to the levelized PECO O&M costs I have used in the lifecycle studies. In cases where published sources were not levelized or expressed in comparable year dollars, I used data from the corporate assumption books to place the published estimates on a comparable basis. I used the same levelizing factors employed in the lifecycle studies where necessary. I have not included data from sources which do not specifically state whether or not their cost estimates are levelized.

The somewhat limited comparison I am able to make reveals that the PECO studies generally have higher nuclear O&M and lower coal O&M than do these studies (the exception is PECO's 1978 coal O&M, which is higher than the comparison estimate, albeit by a smaller percentage than is nuclear O&M). Again, this conclusion tends to support the finding that the PECO studies were based on assumptions which were reasonable and even conservative when compared to published contemporaneous estimates.

Q. Have you been able to compare the fuel cost growth rates used by the Company to published sources?

A. Yes. First, in Exhibit WHH-28 I have summarized the real fuel growth rates used in the lifecycle PECO studies. I should again point out that for 1975 to 1977 the values I used were based only on PECO's escalation rates from the year of the analysis to the first year after the plan was due on-line. The escalation rates for 1978 and 1979 were obtained from the corporate assumption book; the 1980 rates shown in this table are approximate and are the result of my back-calculations from the Company's levelized values.

Exhibit WHH-29 shows real fuel growth rates obtained from several of the references I have surveyed. The Company's coal growth rates appear to be generally consistent with the EIA's series of forecasts and thus somewhat higher than those of other forecasters on average. This may or may not reflect a different view of coal markets. It is important to distinguish between escalation for coal of a particular type (e.g., medium sulfur Appalachian underground) from coal escalation more generally. This is particularly true if the comparison is to the average for all utility-burned coal since the shift toward low-cost Western coal will bias the overall escalation rate downward. In any event, the PECO forecast was within the general range of publicly available forecasts. The Company's nuclear fuel forecasts track the few available observations, tending to rise above the forecasts of these other studies in the 1979-1980 period.

Q. I note that you have made no mention of nuclear decommissioning cost, post-completion capital expenditures, or high level waste disposal costs. Were these costs included in the various PECO and non-PECO studies which you have reviewed?

A. By and large, these were considered to be "non-issues" throughout this period. Capital additions (for both coal and nuclear plants) were almost universally ignored as neglectably small or offsetting at least through 1980. Decommissioning expenses were generally thought to be "lost in the rounding" by most analysts until the very late 1970s or 1980; PECO began including them explicitly in about 1980. Waste disposal cost was thought to be negative for the early part of the period (due to reprocessing) and negligibly small subsequently. Thus, PECO was also "mainstream" with respect to the inclusiveness of its studies.

Q. Does this conclude your testimony?

A. Yes.

Exhibit WHH-1

PRUDENTLY ANTICIPATED RESERVE MARGINS: BASE CASE (2 PERCENT LOAD GROWTH)

Year	Peak Load	Capacity Required with 25 Percent Reserve Margin	Planned Capacity	Surplus (Deficit)
1	5,000	6,250	6,400	150
2	5,100	6,375	6,400	25
3	5,202	6,503	6,800	297
4	5,306	6,633	6,800	167
5	5,412	6,765	6,800	35
6	5,520	6,901	6,800	(101)
7	5,631	7,039	7,700	661
8	5,743	7,179	7,700	521
9	5,858	7,323	7,700	377
10	5,975	7,469	7,700	231

Exhibit WHH-2

PRUDENTLY ANTICIPATED RESERVE MARGINS: RANGE BASED ON LOAD GROWTH VARIATION

		Requirements and Excess Reserves			
Year	Planned Capacity	Plus 1 Percent Load Growth		Minus 1 Percent Load Growth	
1	6,400	6,313	87	6,188	212
2	6,400	6,520	(120)	6,250	150
3	6,800	6,697	103	6,313	487
4	6,800	6,898	(98)	6,376	424
5	6,800	7,105	(305)	6,439	361
6	6,800	7,318	(518)	6,504	296
7	7,700	7,537	163	6,569	1,131
8	7,700	7,764	(64)	6,635	1,065
9	7,700	7,996	(296)	6,701	999
10	7,700	8,236	(536)	6,768	932

Exhibit WHH-3

Model for Adjusting Nuclear Plant Schedules to a Common Basis

(Based on plants with Commercial Operation Dates
2 years before to 2 years after Limerick 1)

Variable	Coefficient	T Statistic	T-Stat Signif	Variable Definition
PERIOD	Dependent			Years Between CP Date and Comercial Operation Date
AEISUTIL	2.0793	3.096	0.0043	If Utility is the A/E, AEISUTIL=1; AEISUTIL=0 Otherwise
MIDATL	2.6356	3.678	0.0010	If Unit is in NY, PA, NJ, or MD, then MIDATL=1, MIDATL=0 Otherwise
CTOWER	-0.8394	-1.613	0.1176	If Plant has a Cooling Tower then CTOWER=1, CTOWER=0 Otherwise
WTHRDPR	-0.0169	-1.727	0.0947	Mean Days of Annual Precipitation
FLDELAY	0.1478	2.055	0.0489	Number of Delays of Fuel Load Date
LNMW	4.0736	1.548	0.1324	Natural Logarithm of Net Megawatts
LNAEEXP	-0.3178	-1.354	0.1863	Natural Logarithm of Number of Nuclear Plants A/E has Done
(CONSTANT)	-16.767	-0.895	0.3783	Value of PERIOD if values of all explanitory variables are zero

Statistics of Model:

Adjusted R^2	0.568
Standard Error	1.251
F Ratio	7.760
Number of Observations	37

Ex[illegible] WHH-4

DEVIATION FROM PREDICTED SCHEDULE

FOR 37 PLANTS DUE ON LINE 2/84–2/88

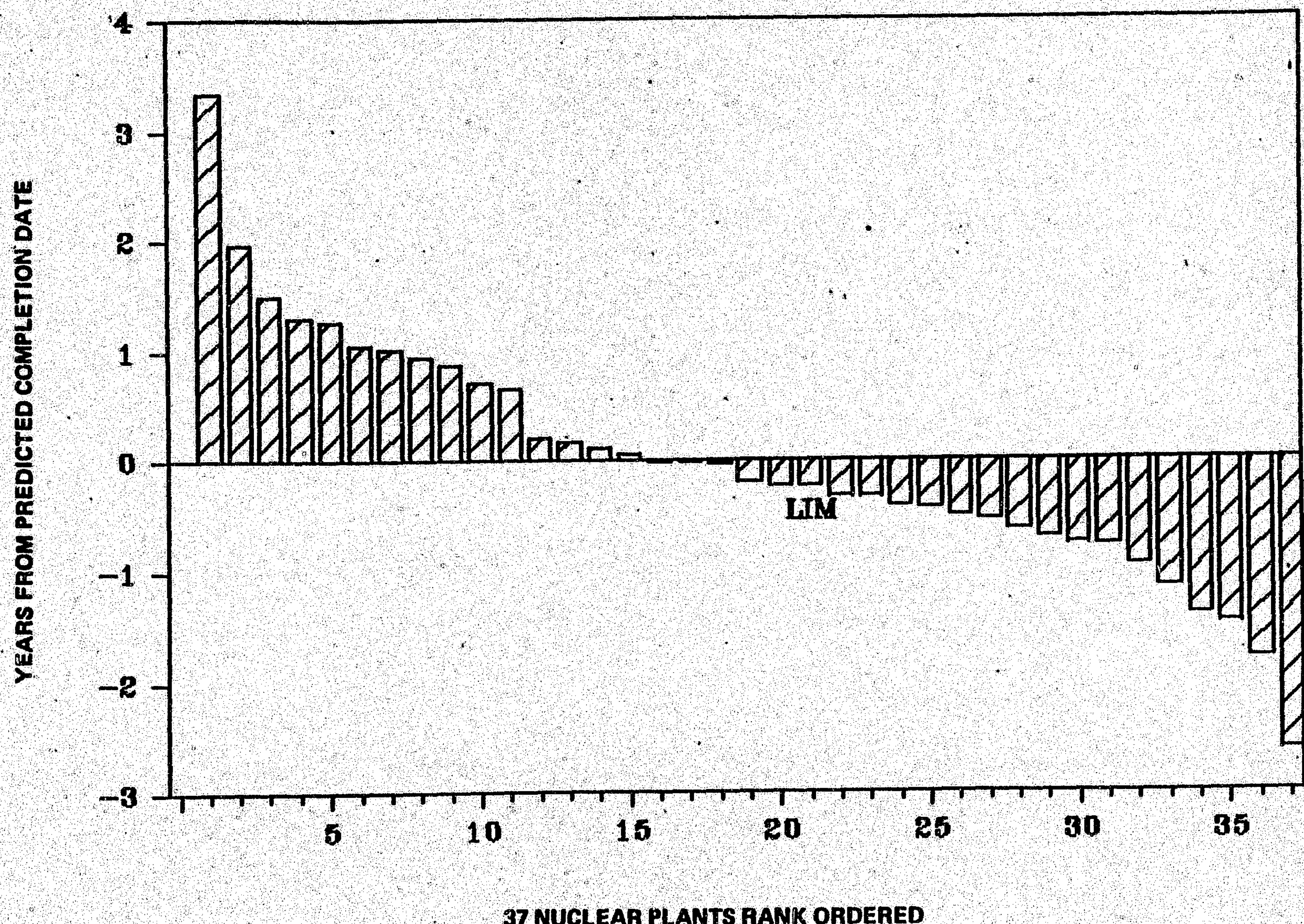


Exhibit WHH-5

Model for Adjusting Nuclear Plant Schedules to a Common Basis

(Based on plants receiving Construction Permits
2 years before to 2 years after Limerick 1)

Variable	Coefficient	T Statistic	T-Stat Signif	Variable Definition
PERIOD	Dependent			Years Between CP Date and Comercial Operation Date
AEISUTIL	1.5545	1.678	0.1020	If Utility is the A/E, AEISUTIL=1; AEISUTIL=0 Otherwise
LNMW	11.2213	3.463	0.0014	Natural Logarithm of Net Megawatts
WTHRDPR	0.0411	2.008	0.0522	Mean Days of Annual Precipitation
FIRST1	-1.4709	-2.025	0.0504	If Unit is first of a multiple, then FIRST1=1, FIRST1=0 Otherwise
MIDATL	2.2553	1.875	0.0689	If plant is in NY, PA, NJ, or MD, then MIDATL=1, MIDATL=0 Otherwise
WTHRSNOW	-0.0297	-1.354	0.1840	Mean annual snowfall in inches
(CONSTANT)	-69.449	-3.016	0.0047	Value of PERIOD if values of all explanitory variables are zero

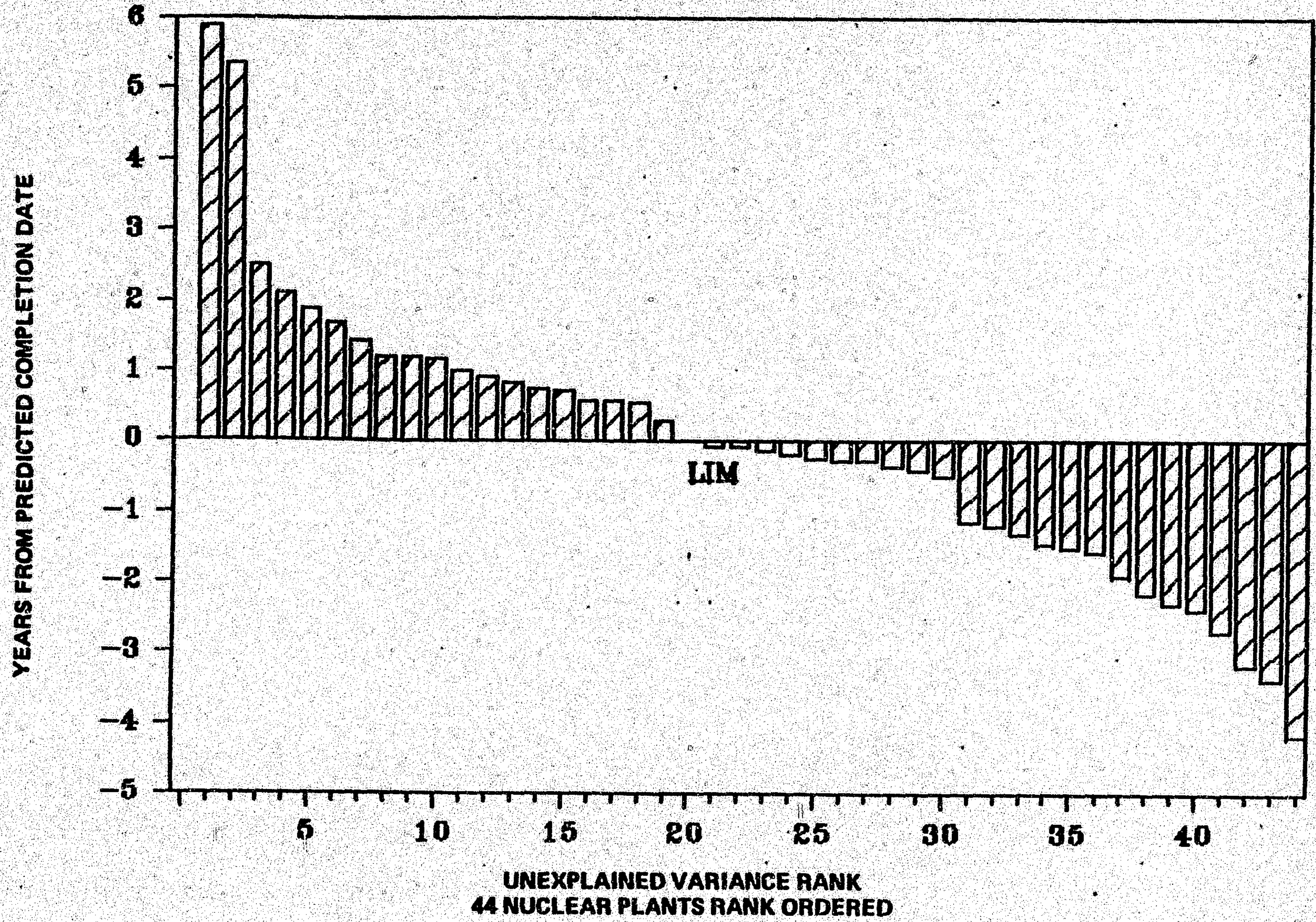
Statistics of Model:

Adjusted R^2	0.331
Standard Error	2.134
F Ratio	4.469
Number of Observations	44

Exhibit WHH-6

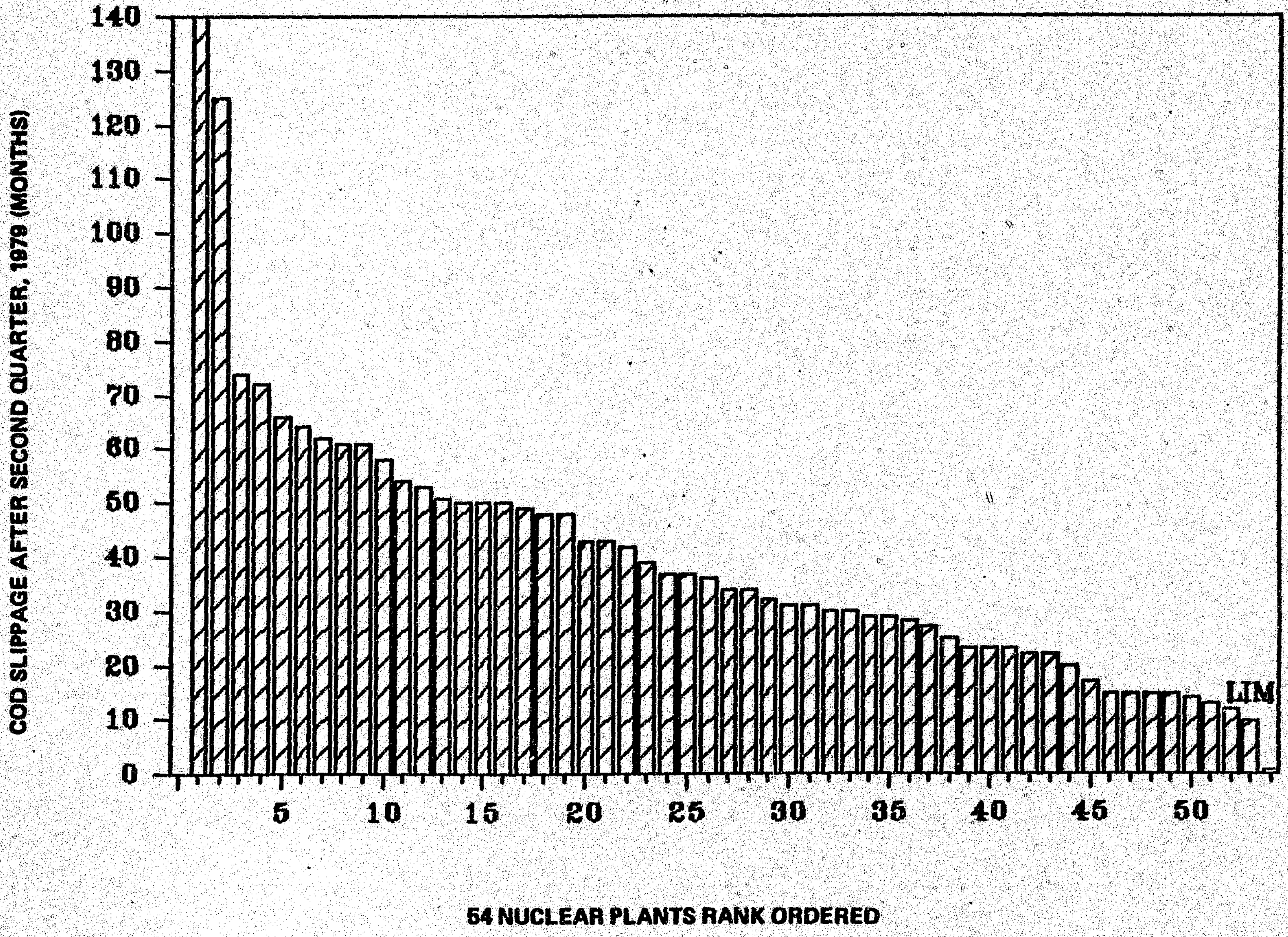
DEVIATION FROM PREDICTED SCHEDULE

FOR 44 PLANTS WITH CP DATES 6/72–6/76



Exhib[illegible] HH-7

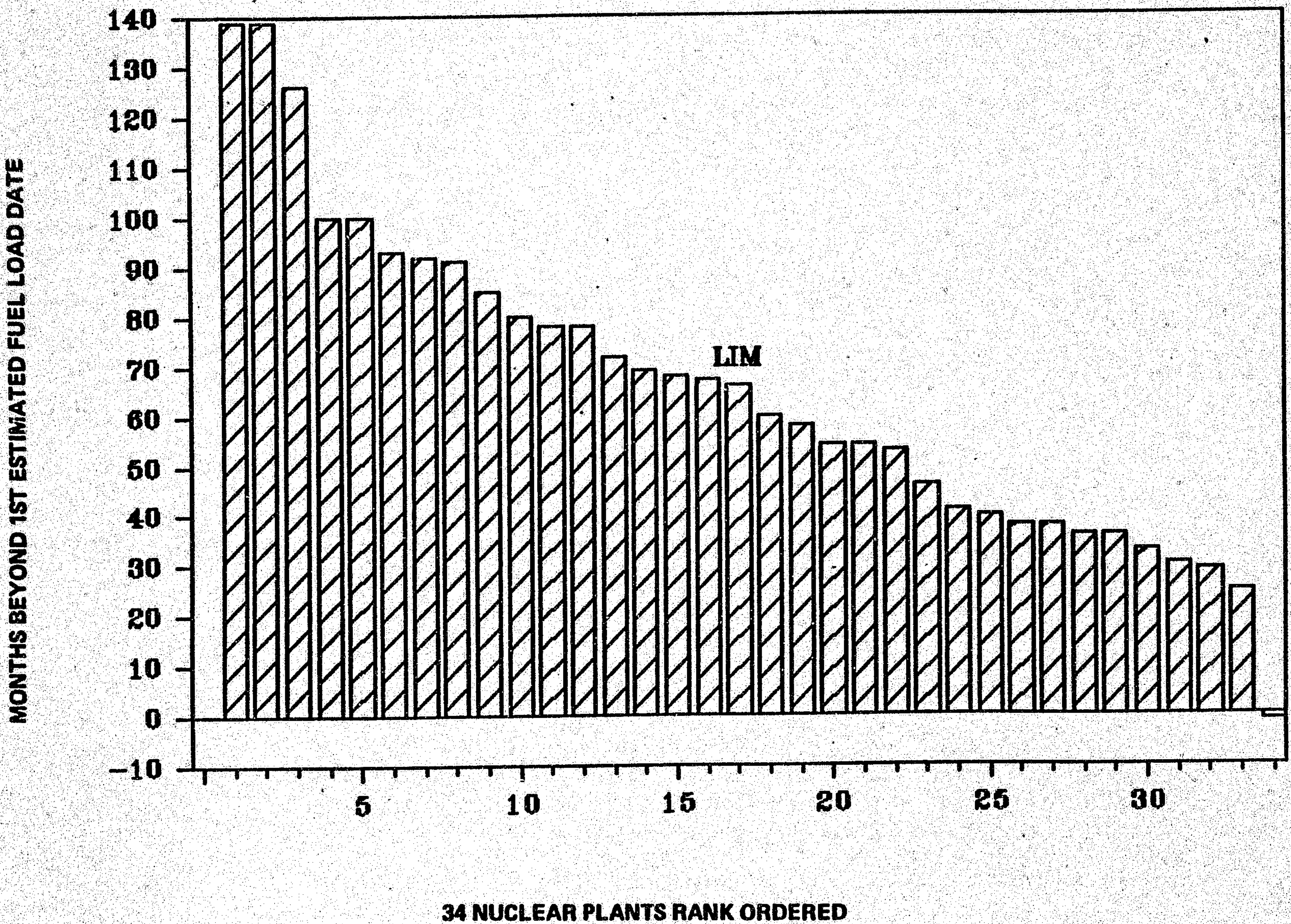
COMMERCIAL OPERATION DATE SLIPPAGE
FOR PLANTS DUE ON LINE AFTER MARCH '79



Ex[illegible]WHH-8

FUEL LOAD DATE SLIPPAGE

FOR 34 PLANTS DUE ON LINE AFTER 3/79



ACCURACY OF CONSTRUCTION SCHEDULE FORECASTS

FOR 44 PLANTS WITH CP DATES 6/72 – 6/76

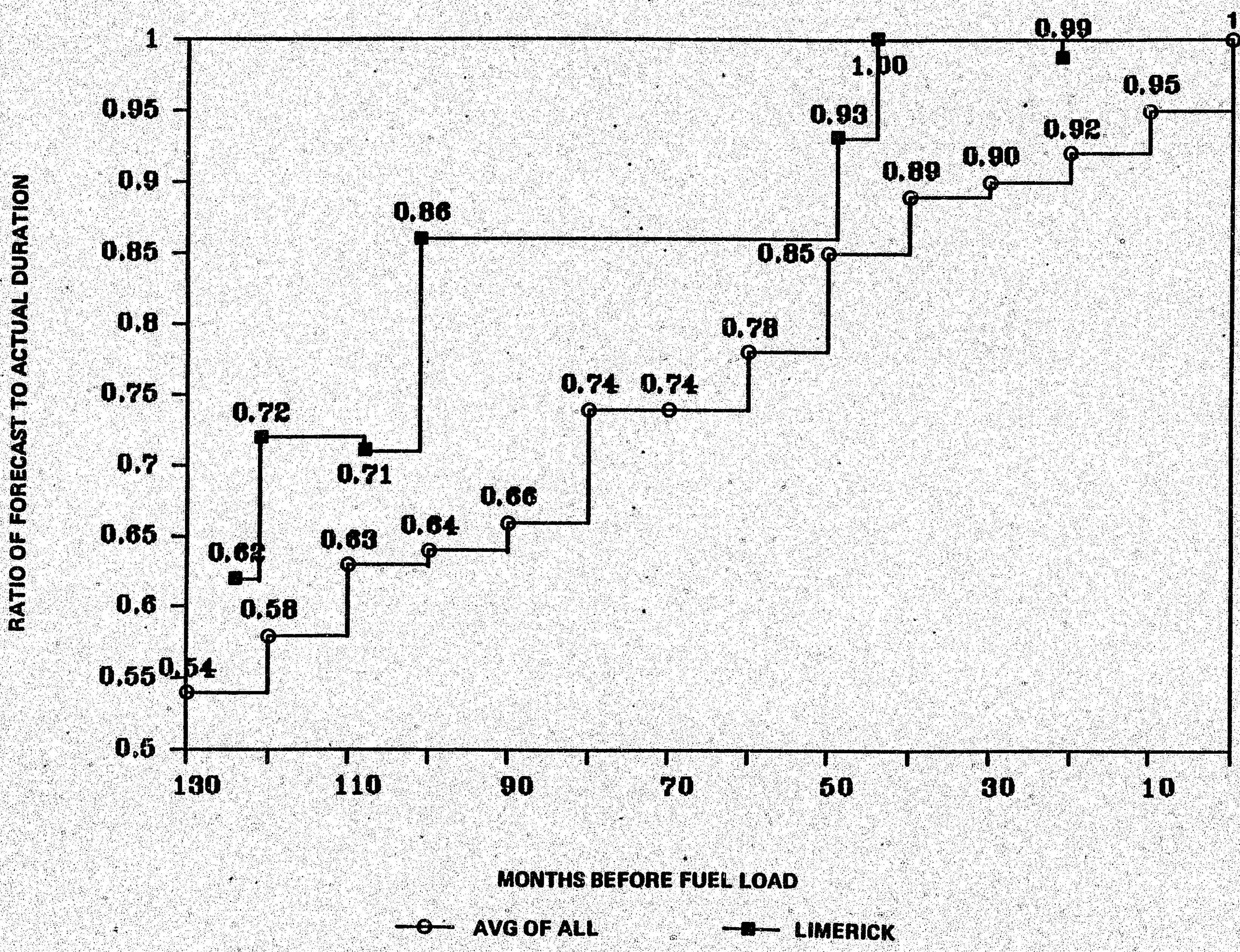


Exhibit WHH-10

10-YEAR PEAK LOAD FORECAST COMPARISON

Year	PECO	Elec. World (United States)	DOE* (United States)	NERC (United States)	MAAC (Region)
1974	6.0%	5.6%	6.5-6.7%	7.7%	6.6%
1975	6.7	5.6	--	7.2	5.7
1976	5.4	6.2	5.9	6.7	5.6
1977	5.0	5.8	--	6.2	5.0
1978	2.5	4.8	4.6	5.4	3.5
1979	2.4	3.9	3.8	4.9	3.1
1980	1.7	4.2	2.9	4.3	2.5
1981	1.1	3.1	2.6	3.5	2.4
1982	0.9	2.8	2.4	3.1	1.9

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* PECO, Electric World, and NERC use a 10-year forecast horizon, while DOE uses an horizon that ranges from 10 to 13 years.

Exhibit WHH-11

PEAK LOAD GROWTH -- A COMPARISON OF FORECASTS WITH HISTORIC TRENDS (Prior 10 Years)

	PECO			Six Other Pennsylvania Utilities	
Year	History	Forecast From Last Actual	Weather Normalized Forecast	History	Forecast
1973	6.4%	8.1%	7.4%	6.87%	6.40%
1974	6.6	6.0	6.1	6.54	6.02
1975	5.2	6.7	5.7	5.65	5.43
1976	5.1	5.4	5.5	5.42	5.13
1977	3.8	5.0	4.2	5.22	4.75
1978	4.7	2.5	3.2	4.64	4.53
1979	2.6	2.4	2.6	4.40	3.57
1980	2.1	1.7	1.6	3.03	2.82
1981	2.6	1.1	1.6	2.93	2.67
1982	1.5	0.9	0.9	2.91	2.20
1983	0.7	0.5	0.8	0.70	3.18

Exhibit WHH-12

SELECTED LIMERICK ECONOMICS STUDIES

Year of Study	In-Service Date	Limerick Advantage Relative to Coal Alternative
14 November 1975	1981-1983	12.5 mills/kWh
21 October 1976	1983-1985	11.3 mills/kWh
2 June 1977	1983-1985	8.8 mills/kWh
3 July 1978	1983-1985	1.3 mills/kWh
1979	1985-1987	$509-$1,297 million
9 October 1980	1985-1987	9.7 mills/kWh

NOTE: All Limerick advantages shown relative to coal alternative. 1979 value (obtained from E. Kasum's R-79060865 testimony) represents cumulative savings through 1992.

Exhibit WHH-13

LIFECYCLE GENERATION ECONOMICS
LIMERICK VERSUS HYPOTHETICAL COAL PLANT
(Levelized Mills/kwh)

Year of Study	Limerick Generation Cost	Coal Plant Generation Cost	Limerick Advantage
1975	38.6	90.5	51.9
1976	56.3	113.8	57.5
1977	52.3	101.6	49.3
1978	52.1	85.9	33.8
1979	63.5	98.1	34.6
1980	88.8	108.6	19.8

SOURCE: See testimony.

Exhibit WHH-14

LIFE CYCLE GENERATION ECONOMICS
"TO GO" LIMERICK VERSUS HYPOTHETICAL COAL PLANT
(Levelized mills/kWh)

Year of Study	"To Go" Limerick Generation Cost	Coal Plant Generation Cost	"To Go" Limerick Advantage
1975	31.1	90.5	59.4
1976	44.4	113.8	69.4
1977	38.2	101.6	63.4
1978	34.8	85.9	51.1
1979	41.9	98.1	56.2
1980	50.2	108.6	58.4

SOURCE: See testimony.

Exhibit WHH-15

ESTIMATES OF COAL AND NUCLEAR GENERATION COSTS

Source	Nuclear Generating Cost	Coal Generating Cost	Comments
(4), February 1976	18 mills/kwh	22 mills/kwh	
(5), December 1976	51 mills/kwh	65 mills/kwh	1987-1989 comparison
(6), April 1977			Coal plant favored only under highest inflation scenario with highest fixed charge rates
(7), October 1977			Average nuclear costs lower than coal in each of six U.S. regions
(8), 1978			Nuclear favored over coal under base case assumption
(10), August 1978	35 mills/kwh	42 mills/kwh	1977 dollars
(11), September 1978	63.8 mills/kwh	65.2 mills/kwh	10-year levelized costs
(12), December 1978	10.5 ¢/kwh	11.64 ¢/kwh	1990 dollars; mid-Atlantic region
(13), 1979			Nuclear power projected to be most economical source of baseload generation by 1990
(14), February 1979	108.8 mills/kwh	129.2 mills/kwh	Multi-unit BWR vs. coal, no reprocessing at 70% capacity factor
(15), February 1979	7.5¢/kwh	10.6 ¢/kwh	1990 in-service dates

[Table continued on following page.]

Exhibit WHH-15 (Continued)

ESTIMATES OF COAL AND NUCLEAR GENERATION COSTS

Source	Nuclear Generating Cost	Coal Generating Cost	Comments
(17), October 1979	68 mills/kwh	77 mills/kwh	Eastern plants; 1990-1992 in-service dates. Western plants show coal advantage.
(18), December 1979	4.4 ¢/kwh	6.0 ¢/kwh	Northeastern coal plant; 1986 in-service date. Short-haul western coal plants show coal advantage
(20), January 1980			Nuclear favored over coal under virtually all cases with 20-year levelized costs and in most cases with 10-year levelized costs
(21), December 1980	133 mills/kwh	182 mills/kwh	1991-1992 plants; life-cycle costs; 1980 dollars
(22), September 1981	133 mills/kwh	168-201 mills/kwh	1980 dollars; 1993 in-service dates
(24), 1981	131 mills/kwh	182 mills/kwh	1991-1992 in-service dates; middle inflation case; 1990 dollars

NOTE: See Exhibit WHH-16 for key to source references.

Exhibit WHH-16

REFERENCES FOR COAL AND NUCLEAR GENERATION ECONOMIC STUDIES

1. "Power Plant Capital Costs Current Trends and Sensitivity to Economic Parameters," U.S. AEC, WASH-1345, October 1974.

2. "The Economic Impact of the EPA's Air and Water Regulations on the Electric Utility Industry," U.S. Environmental Protection Agency, Office of Planning and Evaluation, Temple Barker & Sloane, November 1975.

3. Economic Growth in the Future, Edison Electric Institute, 1976.

4. National Energy Outlook 1976, Federal Energy Administration, February 1976.

5. "The Economics of Nuclear Power," L. F. Reichle, 14 December 1976.

6. "Economic Comparison of Coal and Nuclear Electric Power Generation," Gibbs and Hill, April 1977.

7. "Comparing Coal and Nuclear Generating Costs," EPRI Journal, October 1977.

8. Annual Report to Congress 1977, U.S. Department of Energy, Energy Information Administration, Arril 1978.

9. Supply 77, EPRI, May 1978.

10. "Economics of Nuclear Power," Rossin and Rieck, Science, Vol. 201, No. 18, August 1978.

11. "Dramatic Changes in the Costs of Nuclear and Fossil-Fired Plants," EBASCO, September 1978.

12. "Estimated Costs of Coal and Nuclear Generation," L. J. Perl, 12 December 1978.

13. Annual Report to Congress 1978, U.S. Department of Energy, Energy Information Administration, 1979.

14. Total Generating Costs, Coal and Nuclear Plants, NUREG-0248, United Engineers & Constructors, February 1979.

Exhibit WHH-16 (Continued)

REFERENCES FOR COAL AND NUCLEAR GENERATION ECONOMIC STUDIES

15. "The Economics of Nuclear Power," W. J. L. Kennedy, 26 February 1979.

16. Technical Assessment Guide, EPRI, July 1979.

17. "The Economics of Nuclear Versus Coal," L. F. Reichle, EBASCO, 30 October 1979.

18. "Economics of Nuclear Power," Westinghouse, December 1979.

19. Annual Report to Congress 1979, U.S. Department of Energy, Energy Information Administration, 1980.

20. "Economic Comparison of Coal and Nuclear Electric Power Generation," Gibbs & Hill, January 1980.

21. "An Economic Comparison of Nuclear and Coal-Fired Generation," G. R. Corey, Commonwealth Edison Company, 1 December 1982.

22. 1980 Annual Report to Congress, U.S. Department of Energy, Energy Information Administration, March 1981.

23. "U.S. Nuclear Generation Economics," C. W. Mycoff, Westinghouse, Nuclear Energy Digest, September 1981.

24. "An Economic Comparison of Nuclear, Coal and Oil-Fired Electric Generation in the Chicago Area," G. R. Corey, Annual Review of Energy, 1981.

Exhibit WHH-17

NUCLEAR PLANT COSTS USED IN
PHILADELPHIA ELECTRIC STUDIES

Date of Study	In-Service Date	Cost ($/KW)
11/14/75	1981-1983	$ 949
10/21/76	1983-1985	1,201
06/02/77	1983-1985	1,201
07/03/28	1983-1985	1,232
1979*	1985-1987	1,478
10/09/80	1985-1987	1,840

* Testimony of E. Kasum in R-79060865.

Exhibit WHH-18

ESTIMATES OF NUCLEAR CAPITAL COST

Source	In-Service Date	Cost/KW	Adjusted Date	Adjusted Cost/KW	Comments
(1), October 1974	1983	720			
(2), November 1975	1981	616			
(2), November 1975	1983	705			
(4), February 1976	1982	500-550			1975 dollars
(5), December 1976	1987-1989	1,270			Eastern plant
(6), April 1977	1987	946-1,299			
(7), October 1977	1986	757-901	1984	1,147-1,365	Original estimate in 1976 dollars; Northeast plant
(9), May 1978	1985	790	1984	1,202	Original estimate in 1976 dollars
(10), August 1978	Late 1980s	692	1986	1,135	Original estimates in 1977 dollars
(11), September 1978	1988-1990	1,648	1985-1987	1,396	
(12), December 1978	1990	2,297	1986	1,840	First unit; 1,100 MW
(13), 1979	1985	775	1986	1,208	Original estimate in 1978 dollars
(14), February 1979	1985	1,038	1986	1,097	Average for multi-unit BWRs
(15), February 1979	1990	1,937	1986	1551	

[Table continued on following page.]

Exhibit WHH-18 (Continued)

ESTIMATES OF NUCLEAR CAPITAL COST

Source	In-Service Date	Cost/KW	Adjusted Date	Adjusted Cost/KW	Comments
(16), July 1979	1978	810	1986	1,780	Original estimate in 1978 dollars; Northeast plant
(17), October 1979	1990-1992	1,670	1985-1986	1,085	Eastern plant
(18), December 1979	1984	1,000-1,300	1986	1,188-1,545	
(20), January 1980	1990-1992	2,368	1985-1987	1,539	
(21), December 1980	1991-1992	2,035	1985-1986	1,214	
(23), September 1981	1991-1993	2,641	1985-1987	1,574	
(24), 1981	1991-1992	2,035	1985-1987	1,214	

NOTE: See Exhibit WHH-16 for key to source references.

Exhibit WHH-19

COMPARISON OF PECO ESTIMATES TO
ADJUSTED PUBLISHED SOURCES
NUCLEAR PLANT CAPITAL COSTS
($/KW)

PECO Estimate	Adjusted Comparison Studies: Estimate	Source
1978: 1,232	1,147-1,365	(7)
	1,202	(9)
1979: 1,478	1,135	(10)
	1,396	(11)
	1,840	(12)
	1,208	(13)
	1,097	(14)
	1,551	(15)
1980: 1,840	1,780	(16)
	1,085	(17)
	1,188-1,545	(18)
	1,539	(20)

NOTE: See Exhibit WHH-16 for key to source references.

Exhibit WHH-20

COMPARISON OF NUCLEAR PLANT COST ESTIMATES FOR MULTIPLE UNIT PLANTS SCHEDULED TO BEGIN OPERATION WITHIN ONE YEAR OF LIMERICK

	Date of Estimate				
	1976	1/1978	12/1978	1/1980	12/1980
Limerick ($/KW)	1,101	1,199	1,514	1,953	1,953
Number of Two-Unit Plants	2	2	2	4	8
Average Estimate ($/KW)	1,005	987	1,239	1,347	1,371

Exhibit WHH-21

COAL PLANT COSTS USED IN PHILADELPHIA ELECTRIC STUDIES

Date of Study	In-Service Date	Cost ($/KW)
11/14/75	1981-1983	$ 695
10/21/76	1983-1985	910
06/02/77	1983-1985	910
07/03/28	1983-1985	792
1979*	1985-1987	1,025
10/09/80	1985-1986-1987	1,066

Note: All coal units equipped with scrubbers.

* Testimony of E. Kasum in R-79060865.

Exhibit WHH-22

ESTIMATES OF COAL PLANT CAPITAL COST

Source	In-Service Date	Cost/KW	Adjusted Date	Adjusted Cost/KW	Comments
(1), October 1974	1983	626			*
(2), November 1975	1981	415			*
(2), November 1975	1983	520			*
(4), February 1976	1982	440-480			1975 dollars
(5), December 1976	1987-88-89	1,150			Eastern plant
(6), April 1977	1987	798-1,043			
(7), October 1977	1986	638-759	1984	964-1,147	Original estimate in 1976 dollars; Northeast plant
(9), May 1978	1985	650	1984	989	Original estimate in 1976 dollars
(10), August 1978	Late 1980s	638	1986	1,046	Original estimate in 1977 dollars
(11, September 1978	1988-89-90	1,266	1985-86-87	1,072	
(12), December 1978	1990	1,635	1986	1,310	
(13), 1979	1985	595-680	1986	921-1,053	Original estimate in 1978 dollars
(14), February 1979	1985	885	1986	935	Average for multi-unit station

[Table continued on following page.]

Exhibit WHH-22 (Continued)

ESTIMATES OF COAL PLANT CAPITAL COST

Source	In-Service Date	Cost/KW	Adjusted Date	Adjusted Cost/KW	Comments
(15), February 1979	1990	1,509	1986	1,209	
(16), July 1979	1978	765	1986	1,681	Original estimate in 1978 dollars
(17), October 1979	1990-91-92	1,231	1985-86-87	800	Eastern site
(18), December 1979	1984	800-1,000	1986	950-1,188	
(19), 1980	1985	940-1,025	1986	1,702-1,856	Original estimate in 1979 dollars
(20), January 1980	1990-91-92	1,791	1985-86-87	1,164	
(21), December 1980	1991-1992	1,695	1985-1986	1,011	
(23), September 1981	1991-92-93	1,990	1985-86-87	1,187	
(24), 1981	1991-1992	1,695	1995-1986	1,011	

NOTE: See Exhibit WHH-16 for key to source references.

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* Reference does not explicitly state scrubbed coal units.

Exhibit WHH-23

COMPARISON OF PECO ESTIMATES TO
ADJUSTED PUBLISHED SOURCES
COAL PLANT CAPITAL COSTS
($/KW)

PECO Estimate	Adjusted Comparison Studies: Estimate	Source
1978: 792	964-1,147	(7)
	989	(9)
1979: 1,025	1,046	(10)
	1,072	(11)
	1,310	(12)
	921-1,053	(13)
	935	(14)
	1,209	(15)
1980: $1,066/KW	1,681	(16)
	800	(17)
	950-1,188	(18)
	1,702-1,856	(19)
	1,164	(20)

Exhibit WHH-24

ESTIMATES OF COAL AND NUCLEAR PLANT CAPACITY FACTORS
(Percent)

Source	Coal Capacity Factor	Nuclear Capacity Factor	Comments
(2), November 1975	55	64.2	Forecasts for 1980
(3), 1976	46-50	65-68	Forecats for 1980-1985.
(4), February 1976	70	70	
(5), December 1976	75	75	
(6), April 1977	70	70	
(7), October 1977	66	66	
(10), August 1978	60	60	
(12), December 1978	62	65	Average for different unit sizes
(13), 1979	64	70	
(14), February 1979	70	70	
(15), February 1979	60	60	
(16), July 1979	71-74	71	Equivalent annual availability
(17), October 1979	70	70	
(18), December 1979	78	77	1978 large plant availability
(19), 1980	59	70	

[Table continued on following page.]

Exhibit WHH-24 (Continued)

ESTIMATES OF COAL AND NUCLEAR PLANT CAPACITY FACTORS
(Percent)

Source	Coal Capacity Factor	Nuclear Capacity Factor	Comments
(20), January 1980	70	70	Base case value
(21), December 1980	60	60	
(22), March 1981	59	66	
(23), September 1981	70	70	
(24), 1981	60	60	

NOTE: See Exhibit WHH-16 for references.

Exhibit WHH-25

OPERATIONS AND MAINTENANCE EXPENSES USED IN PHILADELPHIA ELECTRIC STUDIES (mills/kwh)

Date of Study	In-Service Date	Nuclear O&M	Coal O&M
11/14/75	1981-1983	2.26	4.48
10/21/76	1983-1985	2.43	5.06
06/02/77	1983-1985	4.48	5.06
07/03/78	1983-1985	3.99	4.51
1979	1985-1987	4.69	2.86
10/09/80	1985-1987	17.3	19.6

NOTE: Values are first-year costs except for 1980 which are life cycle costs. 1979 values computed as described in text.

Exhibit WHH-26

ESTIMATES OF COAL AND NUCLEAR O&M EXPENSES
(Mills/kwh)

Source		Nuclear O&M	Coal O&M	Comments
(6)	April 1977	2.28	2.77	1977 dollars; not levelized
(10)	August 1978	2	5	1977 dollars; late 1980s plant
(11)	September 1978	1.8	1.8	10-year levelized; 1988-1990 plant
(12)	December 1978	8.4	13.7	1990 dollars; 1,000 MW nuclear plant; 700 MW coal plant; levelized
(14)	February 1979	3.05	10.2	Average of 1985 5% and 8% escalation costs, levelized at 10%. Two unit BWR vs. 3 unit high-sulfur coal; 70% capacity factor
(15)	February 1979	4.0		1990 dollars; not levelized
(16)	July 1979	2.0	5.7	1978 dollars at 70% capacity factor
(20)	January 1980	2.75	3.95	1979 dollars at 70% capacity factor; not levelized
(23)	Septemer 1981	16	26	1991-1993 plant; Pa coal plant; levelized

NOTE: See Exhibit WHH-16 for references.

Exhibit WHH-27

COMPARISON OF PECO ESTIMATES TO
ADJUSTED PUBLISHED SOURCES OF O&M COSTS
(Levelized Mills/kWh)

	PECO		Adjusted Comparison Studies		
	Coal	Nuclear	Coal	Nuclear	Source
1978	8.2	7.2	7.3	6.0	(6)
1979	5.2	8.5	11.3	6.9	(12)
			10.7	3.2	(14)
			--	5.9	(15)
1980	19.6	17.3	14.7	10.2	(20)

NOTE: See Exhibit WHH-16 for references.

Exhibit WHH-28

BASE CASE REAL FUELS ESCALATION RATES

Year	Coal	Nuclear Fuel
1975	3.0	1.0
1976	4.0	3.8
1977	3.0	1.0
1978	3.0	1.0
1979	3.0	2.0
1980	1.0*	3.0*

* Estimated.

Exhibit WHH-29

ESTIMATES OF REAL FUEL PRICE ESCALATION

Source		Nuclear Fuel	Coal	Comments
(2)	November 1975		0% 1976-1990	Approximately 5% inflation 1979-2000
(4)	February 1976		2-3% 1980-1990	Central Appalachian
(7)	October 1977	1.5-1.6%	1.2%	1976-2000
(9)	May 1978	0.3%	0.5%	1978-2000
(11)	September 1978		2% 1978-80; (0.5%) subsequent	
(13)	1979		5.8% 1977-1978 1.5% 1985-1995	Mid-Atlantic Region
(14)	February 1979	1.8%	0%	1985-1990
(15)	February 1979	5%	4%	1978-1990
(16)	July 1979	2.48% 1978-2000	2.6% 1980-1985 2.3% 1983-1990 0.6% 1990-2020	No nuclear fuel reprocessing
(19)	1980		2.6% 1978-1985 1.5% 1985-1990 0.3% 1990-1995	National average
(22)	March 1981		2.7% 1987-1985 1.1% 1985-1990 1.2% 1990-1995	

NOTE: See Exhibit WHH-16 for references.

PECO STATEMENT NO. 16

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SEP 27 1985

SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY
COMMISSION v. PHILADELPHIA ELECTRIC
COMPANY, Docket No. R-850152

DIRECT TESTIMONY OF
DAVID J. FARLING
COOPERS & LYBRAND

ACCOUNTING ISSUES RELATED
TO PHASE-IN PROPOSAL

September 27, 1985

DOCKETED

SEP 27 1985

<u>Testimony of David J. Farling</u>

Q. Please state your name, business address and occupation.

A. David J. Farling, 1900 Mellon Bank Center, Philadelphia, Pennsylvania 19102. I am a Certified Public Accountant, Partner and Chairman of the Electric and Gas Utilities Industry Specialization Program of Coopers & Lybrand.

Q. What is the business of Coopers & Lybrand?

A. Coopers & Lybrand is an international public accounting firm engaged in the business of providing accounting, tax and consulting services.

Q. What are your responsibilities at Coopers & Lybrand?

A. I am responsible for the direction of the Firm's electric and gas utilities industry program which includes advising other professionals and partners on accounting and auditing for public utilities, managing our regulatory and advisory services practice, and speaking on current topical accounting and auditing issues concerning the industry. I serve as the engagement partner or concurring partner for recurring audit examinations and for regulatory and advisory work.

Q. Please describe your educational background.

A. I graduated with honors from Lebanon Valley College with a Bachelor of Science degree, majoring in economics. I also hold a Master of Science degree in Business Administration from the Pennsylvania State University. While at the Pennsylvania State University, I was elected a member of Beta Gamma Sigma, a national honorary society in business administration.

Q. Please describe your professional experience.

A. I joined Coopers & Lybrand in 1958 upon completion of my college education. I became a partner in 1969. I have been actively involved in the Firm's services to electric and gas utility clients since 1971. My experience includes responsibility for the examination of financial statements of electric and gas utilities, representation of clients in accounting and compliance matters before the Federal Energy Regulatory Commission, and presentation of testimony on accounting matters in regulatory proceedings before state and federal jurisdictions. I became co-chairman of the electric and gas industry program for Coopers & Lybrand in 1975 and chairman in 1980.

I served as a member of the American Institute of Certified Public Accountants, Public Utilities Subcommittee from 1979 through 1983, and was Subcommittee Chairman for 1981-83. The objectives of this subcommittee are to review and prepare comments on accounting and auditing pronouncements and proposals of the Federal Energy Regulatory Commission and legislative proposals of the Congress, to issue publications, as needed, on the application of accounting and auditing standards to public utilities, and to communicate with regulatory and industry officials on matters of mutual interest. The exposure draft of Statement of Financial Accounting Standards, No. 71, "Accounting for the Effects of Certain Types of Regulation," was discussed and critiqued during my tenure as chairman of this subcommittee.

I have made presentations on accounting topics before various committees and conferences of the Edison Electric Institute, the American Gas Association, the National Association of Regulatory Utility Commissioners Staff Subcommittee on Accounts, the Pennsylvania Electric Association, and the Electric Council of New England. I am a member of the American Institute of Certified Public Accountants, the Pennsylvania Institute of Certified Public Accountants, and the American Accounting Association.

Q. What have been your responsibilities for services performed by Coopers & Lybrand for the Philadelphia Electric Company (the "Company")?

A. I was the assigned engagement partner for the Firm's services to the Company during the period 1971 to 1979. I presently serve as the concurring partner in our services to the Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the principal accounting issues arising out of the Company's proposal to phase-in the rate increase requested in this proceeding.

Q. Please briefly describe the Company's phase-in proposal.

A. The proposed increase in electric rates will be phased-in over a three-year period, with approximately one-third of the increase in year 1, two-thirds in year 2, and the full amount in year 3. The unrecovered revenues from years 1 and 2 will be recovered over a three-year period beginning in year 4, without recovery of any carrying charges on the unrecovered revenue.

Q. Please briefly describe the accounting procedures which will be employed to reflect the phase-in on the Company's financial statements.

A. In general, the Company will continue to recognize revenue and costs in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, prescribed by the Pennsylvania PUC for use by Pennsylvania electric utilities. The revenue unrecovered under the phase-in proposal during years 1 and 2 of the phase-in will be recorded as operating revenue and as a noncurrent asset in Account 186. When this revenue is billed (i.e., years 4, 5, and 6 of the phase-in), the Company will record an accounts receivable in Account 142, in the amount of the billing and reduce Account 186 by a like amount.

Q. What are the principal accounting issues arising from the Company's phase-in proposal?

A. I believe there are two principal accounting issues associated with the Company's phase-in proposal:

1. Future realization of the unrecovered revenue recorded as a noncurrent asset.

2. Measurement of the economic effect of unrecovered revenue being recovered over an extended period where no return is received on the unrecovered amount.

Q. What accounting standards and principles are relevant to a resolution of these two issues?

A. Resolution of these issues will be governed by application of "generally accepted accounting principles" ("GAAP") for the preparation of financial statements. GAAP refers to the rules and conventions of practice supported or promulgated by an authoritative body of the accounting profession. Presently, the Financial Accounting Standards Board ("FASB") is the authoritative source of accounting principles, having been so designated by the Council of the American Institute of Certified Public Accountants.

The economic effects of regulation can create circumstances that require different accounting for public utilities as compared to unregulated business. Statement of Financial Accounting Standards No. 71 ("Statement 71"), "Accounting For The Effects of Certain Types of Regulation," issued by the FASB in December 1982, presently provides the accounting guidance for the preparation of financial statements for public utilities. Statement 71 establishes the principles to be applied in reporting the effects of various types of rate actions in a utility's financial statements.

Q. What is the current status of Statement 71?

A. As set forth above, Statement 71 was issued in December 1982. In 1984, the FASB requested its staff to examine the application of Statement 71 to certain major events in the electric utility industry, including rate moderation ("phase-in") plans of electric utility companies. In October 1984, the American Institute of Certified Public Accountants Public Utilities Subcommittee completed an Issues Paper, "Application of Concepts in FASB Statement No. 71 To Emerging Issues in the Public Utility Industry," which was made available to the FASB. The issues in this Issues Paper are presently being discussed at a series of meetings of the FASB with the express intention of preparing an amendment to Statement 71. Presently, an exposure draft of the amendment is expected to be issued in the second half of 1985. It is too early to predict whether a final amendment date will be adopted in time to affect financial statements for the year ending December 31, 1985.

Q. Does the Company's phase-in plan meet the requirements of Statement 71 as it is now effective?

A. Yes, for the reasons set forth subsequently, I believe the Company's phase-in plan, as filed, meets the present requirements of Statement 71.

Q. Why is it important that the Company's phase-in plan meet the requirements of GAAP?

A. The Company's financial statements must be prepared in accordance with generally accepted accounting principles. The annual financial statements of the Company are examined and reported upon by Coopers & Lybrand, the Company's outside auditors. In our report, we must express our opinion that these statements fairly present the financial position and the results of operations of the Company in conformity with generally accepted accounting principles consistently applied. If the Company's financial statements were not prepared in accordance with GAAP, they would not be accepted for filing with the Securities and Exchange Commission.

The significance of this requirement to the phase-in plan is of importance. If the Company's phase-in plan is in accordance with GAAP, unrecovered revenue will be reflected in the financial statements, thereby significantly improving earnings and coverage ratios during the phase-in period. Conversely, if the phase-in plan is not in accordance with GAAP, the Company will not be able to recognize an equivalent amount of unrecovered revenue in its financial statements. This would decrease the Company's earnings and coverage ratios during the phase-in.

ACCOUNTING ISSUE I: FUTURE REALIZATION OF UNRECOVERED REVENUE

Q. Turning first to the issue of future realization of unrecovered revenue, please explain the application of Statement 71 to this issue.

A. Statement 71, as presently written, does not specifically address the accounting for rate phase-in plans. However, certain general premises underlying the accounting standards cited in Statement 71 create some uncertainty as to the validity of phase-in programs. Specifically, Paragraph 5b of Statement 71 indicates that Statement 71 is based on the premise that "the regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products." Further, Paragraph 5c states that, "in view of the demand for the regulated services or products and the level of competition direct or indirect 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."

An inherent assumption in the above-cited language of Statement 71 is that a utility's costs, such as those for Limerick 1 would be allocated over time for ratemaking purposes consistent with the provisions of the then applicable uniform system of accounts for such costs under ordinary circumstances. It was further assumed that rates so determined could be collected from customers. Billing of such costs in a subsequent accounting period and collection from customers at that time was not specifically contemplated in formulating accounting standards underlying Statement 71.

However, there is other general guidance which supports the Company's specific proposal. Statement of Financial Accounting Concepts No. 3, issued by the FASB in December 1980, defines assets as probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events. And, paragraph 9 of Statement 71 states that "rate actions of a regulator can provide reasonable assurance of the existence of an asset." Thus, if future recovery of unrecovered revenue is assured and if the deferral of billing is over a reasonably short time period, then "reasonable assurance" of the asset would be provided and the phase-in plan would be acceptable.

For example, in numerous instances, regulatory commissions have deferred recovery of certain non-recurring costs by billing such costs over a period of years. Examples of this practice include storm damage expense, rate case expense, and computer leasing expenses.

Q. Please describe those provisions of a rate phase-in plan which are required for a favorable assessment of the probability of future recovery of the currently unrecovered revenue.

A. First, it is paramount that the rate order contain indisputable language assuring the Company of recovery from the customers of all costs recognized as unrecovered revenue under the rate phase-in plan. Any future condition or requirement on recovery of this revenue would seriously jeopardize the "reasonable assurance of the existence of an asset" and could require removal of the unrecovered revenue from the income statement. Second, the plan of recovery should not require additional regulatory action in a subsequent period. Third, in the determination of the period of recovery for this revenue, consideration should be given to the fact that the longer the period of recovery the greater becomes the risk that the Company may not be able to recover its ongoing current costs plus the unrecovered revenue of a prior period. In my opinion, the Company's plan, if adopted by the Commission, as filed, meets these requirements.

Q. How might the expected amendment to Statement 71 affect the present wording of Paragraph 9 concerning acceptable regulatory action for recovery of unrecovered revenue?

A. The comments of the FASB and its staff at the aforementioned meetings concerning realization of unrecovered revenue in phase-in situations indicate that revised Statement 71 will require that future recovery of currently unrecovered revenue or costs must be contingent solely on the passage of time. Any dependency of total realization on future conditions would, therefore, not be acceptable for unrecovered revenue to be recognized as an asset. In addition, it appears likely that the Statement 71, as amended, will establish a time limit on the length of the deferral period.

Q. Why would the FASB place emphasis on the time period for recovery?

A. As previously stated, in Paragraph 5c of Statement 71, a fundamental premise underlying the accounting standards for regulated companies is that rates set at levels which will recover the enterprise's costs can be charged to and collected from customers. A phase-in plan for the cost of new utility plant is an indication that this underlying premise of Statement 71 may not be valid. In such situations, the rates ultimately billed customers are not the result of the utility's plant costs but the result of market or political forces. As indicated earlier, the longer the period of recovery, the greater becomes the risk that because of these forces, the utility may never be able to fully recover the revenue of a prior period.

ACCOUNTING ISSUE II: MEASUREMENT OF THE ECONOMIC EFFECT OF UNRECOVERED REVENUE WITHOUT A RETURN ON THE UNRECOVERED AMOUNT

Q. Please explain the commentary in Statement 71 applicable to the measurement of the economic effect of currently unrecovered revenue being recovered over an extended period without a return on the unrecovered amount.

A. Paragraph 92 of Statement 71 states that "generally accepted accounting principles do not necessarily require the carrying amount of an intangible asset to be its discounted present value, nor do they necessarily require an enterprise to consider a return on investment when evaluating possible impairment of an intangible or depreciable asset. Accordingly, the Board concluded that it should not impose such a requirement on regulated enterprises."

Q. Why then is the absence of a return on the unrecovered revenue in the Company's proposal a principal accounting issue?

A. Because the FASB staff, as part of the process to amend Statement 71, has proposed to the FASB that the economic effect of not recovering a return on a long-term asset be reflected in the financial statements of the entity in the accounting period that such determination is made in the ratemaking process. This recognition of the time value of money is called discounting.

Q. What are the implications of a discounting requirement to the Company's financial statements?

A. The income statement of the Company in the year of recognition of unrecovered revenue would reflect an amount reducing net income by the difference between the present value and the gross amount of the unrecovered revenue. The longer the time period for billing the unrecovered revenue to the customer the greater the amount of the discount and the larger the amount of the charge on the Company's income statement.

Q. Since the proceedings covering the amendment to Statement 71 will be of concern to the Pennsylvania Public Utility Commission, can you provide an update of the subsequent deliberations of the FASB and your testimony at a later date.

A. Yes, I will be informed on the developments concerning this subject in connection with my position as Chairman of the

Electric and Gas Utilities Industry practice of Coopers & Lybrand.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

Statement No. 17

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

RATE PHASE-IN PROPOSAL

CLASS REVENUE ALLOCATION

RATE DESIGN

DIRECT TESTIMONY OF

RAYMOND C. WILLIAMS

SEPTEMBER 1985

Direct Testimony Of Raymond C. Williams

Q. Please state your name and business address for the record.

A. Raymond C. Williams, 2301 Market Street, Philadelphia, Pennsylvania.

Q. By whom are you employed, Mr. Williams, and in what capacity?

A. I am Manager of the Rate Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I received a Bachelor's Degree in Electrical Engineering from Penn State University in 1950. In 1970, I attended the Cornell University Executive Program in Business Administration which covered a broad curriculum including business management, cost control, economics, finance and accounting. I am a Registered Engineer in Pennsylvania.

Q. Please describe your work experience with Philadelphia Electric Company.

A. Immediately upon graduation from Penn State, I was employed by Philadelphia Electric Company as a junior engineer in the Transmission and Operating Department. I progressed through various job responsibilities and was appointed Electric Superintendent of Western Division (Operations) in 1963. My responsibilities in this position included administering the construction and maintenance of distribution substations and lines, as well as the maintenance of service to all customers in the Division on a twenty-four hour a day basis.

In 1967, I was appointed Assistant Manager of the Rate Division in the Finance and Accounting Department and in

1975 was appointed Manager of that Division. The Rate Division is responsible for the preparation of all rate case filing material and testimony, the administration of rate tariffs, fuel adjustment calculations and filings as well as various cost and economic studies including load testing.

Q. Please describe in greater detail your responsibilities in the Rate Division?

A. As Assistant Manger of the Rate Division, I participated in the preparation and development of data for all of the Company's rate filings since 1968. As Manager, I report to the Vice-President of Finance and Accounting and administer under his direction the various functions of the Rate Division as described above.

Q. Have you been active in any professional organizations?

A. Since 1969, I have been a member of the Load Research Committee of the Association of Edison Illuminating Companies (AEIC). In 1975, I became a member of the Rate Research Committee of the Edison Electric Institute (EEI) and I was a member of Task Force Five of the EPRI/NARUC Utility Rate Design Study.

The purpose of the AEIC Load Research Committee is to review currently available load research data, discussing its implications for electric rate design as well as the problems of obtaining accurate load data. The EEI Rate Research Committee reviews current developments in electric utility ratemaking. Task Force Five was one of ten task forces created to investigate and report on various aspects of the EPRI/NARUC study into alternative electric rate structures. Task Force Five's particular function was to analyze the theoretical and practical aspects of the various rate forms under study as a means of achieving defined ratemaking objectives.

Q. Mr. Williams, have you testified in any previous regulatory proceedings?

A. Yes. I have presented testimony before this Commission in its generic investigation into alternative electric rate structures at Proposed Rule Making Docket No. 7 (1976). My testimony included a statement of the Company's position on the several alternative rate structures and costing methodologies at issue in that proceeding. I presented testimony in the Company's last six Electric Rate Cases at Dockets R.I.D.438, R-79060865, R-80061225, R-811626, R-822291 and R-842590, in support of revenue allocation and rate design. I have also testified before this Commission in the Company's most recent Gas Rate Increase at Docket R-832410 and a prior Steam Rate Increase at Docket R-79040785, in proceedings under Section 1307(e) of the Public Utility Code regarding fuel clause over-or-under collections for electric, gas and steam utilities, and before the Maryland Public Service Commission in support of the Company's request at Case Nos. 7225, 7403, and 7589 for increases in retail electric rates.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's phase-in proposal, the allocation of the increase to the various rate classifications and the rate design.

Q. Please describe the Company's phase-in proposal.

A. As part of this filing, the Company is voluntarily proposing to "phase-in" the requested increase over a three-year period by delaying the billing and collection of a portion of the requested rate increase. It is important to emphasize, however, that as a matter of tariff filing and customer notice, the Company is requesting the legal authority to charge customers the full amount of the requested increase, and that under the tariffs filed by the Company, ratepayers have a legal obligation to pay the full amount of the requested increase. However, for purposes of billing and collection only, the Company is voluntarily proposing to delay billing and collecting a portion of the increase through the application of an Unrecovered Revenue Collection Rider as set forth in Schedule 1 to my testimony. These schedules, of course, are based upon the full amount of the requested increase, and would be revised as part of the Company's compliance tariff filing to reflect any disallowances made in the Commission's final rate order.

Q. Why is the Company proposing to phase-in this rate increase?

A. 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.

Q. Please explain the specifics of the Company's phase-in proposal.

A. As part of this filing, the Company proposes to voluntarily phase-in the rate increase in three steps. Assuming approval of the entire increase, each step would be an increase of 9.4% or $223.6 million so that the total increase of 28.2% or $670.7 million would be billed beginning with the third year after the rate increase is granted. The amount of revenue not billed during the first two years would be collected over three years beginning with the fourth year and continuing through the fifth and sixth years. The Company is not seeking to recover any carrying charges associated with this revenue not yet recovered. For a 500 kWh residential customer the proposed base rate billing excluding STAC and ECR for years one through seven would be as follows:

<u>Rate R Phase-In</u>

Present Rate	$56.25
Year 1	61.78
Year 2	67.32
Year 3	72.85
Year 4	78.38
Year 5	78.38
Year 6	78.38
Year 7	72.85

If the overall rate increase granted by the Commission is less than that originally requested in this filing, any amount disallowed by the Commission would be deducted first from the third year increase and then from the second year increase. Thus, if the total increase granted is less than the full amount requested but more than 18.8%, the first and second year increases would be 9.4% and the remainder would be billed in year three. Similarly, if the total increase is 18.8% or less and more than 9.4%, the increase would be phased-in over two years -- 9.4% in year one and the remainder in year two. If the total increase is 9.4% or less, no phase-in would be implemented.

Similarly, the revenue recovery period would vary with the amount of the increase granted by the Commission. Specifically, if the phase-in occurs over two years rather than three years, then recovery of the revenue not billed in year one would be recovered over a two-year period in years three and four.

Q. How will the phase-in be implemented?

A. Upon completion of the rate case the total rates as allowed would be filed with the Commission together with adjustment factors for each rate block of each rate to reflect the phase-in. Assuming approval of the full amount requested, these adjustment factors would be used to compute the customer bills during the first two years of the phase-in. The full rate increase would be billed during the third year.

The Company also will compute each month for each rate schedule, the difference between the amount the customer would have been billed under the approved tariff rate and the amount actually billed by application of the rate adjustment factor. During the first two years that the new rates are in effect this difference will be recorded as unrecovered revenue. This unrecovered revenue will be carried on the Balance Sheet in Account #186 as a Deferred Debit and there will be a separate subdivision established for each rate classification so that the appropriate amount of unrecovered revenue will be collected from each rate classification. The collection of this revenue will begin in the fourth year with a specific unrecovered revenue factor applicable for each rate block. The collection of unrecovered revenue will continue for a rate class until all of the revenue in Account #186 for that class has been collected.

Collection of the unrecovered revenue will be in a manner similar to the initial delay of the revenue collection. Specifically, adjustment factors designed to recover the revenue over a three-year period will be applied to each block of each rate schedule for each rate class. The Company will precisely track the recovery of revenue from each rate class and cease application of the factor when recovery is complete. Due to sales differences and other factors, the precise recovery time will vary from class to class and may occur in more or less than exactly three years. In addition, the Company would propose to review the recovery factors after the first year of the recovery period and adjust the factors, if necessary, to permit recovery over a three-year period.

The detailed procedures which the Company will employ in applying the phase-in proposal are set forth in Schedule 2 to my testimony. As set forth therein, the Company will calculate the difference between present and proposed rates for each rate block. One-third of that differential will be billed in year one, and two-thirds will not be billed. In year two, two-thirds of the difference will be billed, and one-third not be billed. In year three, the full tariff rate will be billed. In years four through six, one-third of this differential will be added to the tariff prices to recover the revenue not billed in years one and two. I would note that the Company's phase-in proposal is identical in concept to that recently proposed by Pennsylvania Power & Light Company, except that the Company's proposal more precisely tracks revenue billing and recovery by applying billing factors to each component of each rate.

Q. Will you please explain how the rate increase was spread among the various classes of customers.

A. Yes, With Supplement #15, as with all rate design efforts, several factors were considered in developing the distribution of the rate increase to the various classes of customers.

Because of the size of this increase we were concerned that it should be spread as equally as possible to all rate classifications. We were also concerned that the difference between the index of individual class rates of return to the average system rate of return should not be increased. For those classes whose index of return to system average before the rate increase was above 140%, the net increase was limited to zero, that is, the increase was exactly equal to the fuel saving allocated to that class. The remaining base rate increase was then spread to all other classes to produce equal net percentage increases to each class. This application of the rate increase resulted in most classes moving toward the average rate of return with the exception of the RH class. The increase to the RH class was therefore limited to a value which would maintain the 116% index of relative return to the class average.

A summary of the ratio of the rates of return for the various classes is shown below:

	Percent of System Average Rate of Return	
Rate	Before Increase	After Increase
R	96%	96%
RH	116%	116%
OP	343%	244%
GS	126%	116%
PD	97%	98%
HT	84%	96%
SLP	174%	97%
SLS	206%	108%

A review of the return indexes for the major rate classifications relative to the system average return after the rate increase shows a range of 96% to 116%. All of the major rate classes are within 20% of the average rate of return and move toward the system average return with the exception of Rates R and RH which remain constant.

Q. Turning now to the rate structure area, Mr. Williams, please describe the Company's electric service rate structure, referring to the rate classifications listed on page A-5 of Exhibit TPH-2.

A. Residential service is supplied under a combination of three rates. Our basic residential rate is Rate R under which we will supply approximately 77% of our service to residential customers during the future test year.

We also have a separately metered rate (Rate OP - Off-Peak) which offers service on a controlled basis for water heating or other 240 Volt appliances, either with 7-day interruption by time clock or for a small additional charge, 5-day interruption by radio control. Rate OP is used primarily for water heating and accounts for approximately 5% of total residential usage. Residential homes with electric space heating are served under rate RH which is identical to Rate R except that usage above 500 kilowatt-hours per month during the eight winter months is priced approximately 4.4¢ below the comparable price of Rate R, in recognition of the seasonally off-peak nature of the electric heating load on our system. Rate RH will account for approximately 18% of our total residential usage during the future test year.

Our commercial and industrial customers are separated into three categories depending on service voltage. Those customers supplied at secondary voltage, 120 or 240 Volts, are supplied under Rate GS which is a General Service rate available for offices, professional, commercial or industrial establishments, and other applications outside the scope of the residential rates, and is available both with and without demand measurement.

Our second category of commercial and industrial customers are those served at Primary Voltage (4,160 Volts) under Rate PD. We have over 2600 customers served under this rate who have demands ranging from about 25 to 1,000 kilowatts, with the average about 175 kilowatts.

The final class of commercial and industrial customer is Rate HT for service supplied at High Tension voltage of 13.2 kV or above. We have approximately 2300 customers served under this rate and their energy usage accounts for about 50% of the Company's total sales during the future test year. Customers served on this rate include our largest customers, some of which have demands in excess of 100,000 kilowatts.

In addition to the above-described major rate classifications, we have two major street lighting rates: Rate SLP for sevice in the City of Philadelphia where the lighting fixtures are not provided by the Company, and Rate SLS for service in the suburbs where the Company does provide the fixtures. In addition, Rate POL is available for private outdoor lighting throughout the system.

Rate TL is available to Municipalities for service to traffic signal light installed and owned by the Municipalities throughout the territory. Rate BLI is available for service to adjacent utilities where Philadelphia Electric's facilities are more accessible to their customers because of geographical locations.

Q. Mr. Williams, is the Company proposing any changes in rate structure within the various rates in Supplement No. 15?

A. Yes. In both Rates R and RH we propose to increase the customer charge from $4.50 to $4.75. This increase is less than the average increase proposed for these rate classifications and is cost justified using the same approach proposed by the Commission Staff in previous rate cases. The $4.50 customer charge is about 25% of the fully allocated customer cost of $18.50 as developed in the Company's cost allocation at page 43.

Q. What other rate structure changes are being proposed as a part of this filing?

A. We are proposing to increase the differential between the single-phase and three-phase customer charges to the cost difference between these two types of service. Three-phase service requires additional costs for metering, transformer installations and services. Even at $20.50 the three-phase customer charge is only about 55% of the fully cost justified customer charge of $37.05. The present and proposed customer charges are as shown:

	Single-Phase	Three-Phase	Difference
Present	$5.50	$15.20	$9.70
Proposed	$6.00	$20.50	$14.50

Q. Are there any proposed changes within Rate GS?

A. Yes. Rate GS presently consists of two parts: a rate for those customers without demand measurement and a rate for those customers with demand measurement. The rate for customers without demand measurement is constructed so that the customer's bill is the same as it would be if the customer made 220 hours use of registered demand -- in other words, the demand is created for the customer by dividing the monthly kilowatt-hours registered by 220.

Our load studies have shown that the hours use of demand for this group of non-demand measured customers is about 125 hours per month rather than the 220 hours as presently built into the rate. We propose as a part of this filing to revise the hours use of demand used to compute bills for non-demand measured customers from the present 220 hours to 175 hours. This represents a move of about 50% of the distance from the present hours use, which is too high, toward the appropriate 125 hours use level.

In order to simplify the rate, we also propose to eliminate the "without demand measurement" portion of Rate GS and retain the "with demand measurement" portion only. For those customers without demand measurement, the monthly kilowatt-hours will be divided by 175 to create a demand for billing purposes which will be used to calculate the customer's bill. In addition, we have revised the billing demand definition to assure that the billing demand for both measured and non-measured customers using 1100 kWh or less per month will never represent less than 175 hours use.

The increase in pricing for Rate GS has been constructed so that the end block of the rate (greater than 400 hours' use) does not receive any increase and in fact is decreased as a result of the fuel roll-out from base rates. This treatment is consistent with the relationship of revenue to cost within the rate. The revenue and cost curves shown on pages 55 to 58 of Exhibit WFS-1 show that at high hours of use of demand the GS revenue is above the GS cost to serve curve whereas for lower hours of use the revenue is below the cost to serve curve. In order to further improve the relationship between cost and revenue the first block of the rate is revised from 65 to 80 hours use of the billing demand.

Q. Are there other rate structure changes being proposed?

A. Yes. Although the suburban street lighting schedule Rate SLS receives a net zero increase, that is, the rate increase for the class is completely offset by the fuel savings allocated to the class, the rate increase has been assigned to those lamps (generally the smaller sizes of lamps) that are now below the cost to provide service to them. The fuel savings, of course, go to each lamp based upon the kWh use of that lamp. The effect of this treatment is to continue the closure between revenue and the cost to serve for each of the lamp sizes within the Rate SLS classification. The net effect on any one Municipality is a small increase or decrease depending on the mix of lamp sizes in service.

Q. Mr. Williams as a part of the Order in the last rate case, Philadelphia Electric was directed to prepare and submit to the Commission studies indicating the cost of providing service to SEPTA and AMTRAK. Have those studies been completed?

A. Yes. We have made a careful study of the cost to serve SEPTA and AMTRAK. As set forth in Mr. Sundermeir's Testimony, a complete analysis has been made of the distribution facilities to reach the numerous points of service for each of these two customers and the cost to serve each customer has been calculated. A customer demand and energy rate has been developed for each customer to provide the system average return. The energy charge of each rate is the same as the end block of Rate HT and time of use credits and surcharges applicable to Rate HT would also be applicable to the rates for SEPTA AND AMTRAK.

These two new rates have been designated EP-S (Electric Propulsion - SEPTA) and EP-A (Electric Propulsion - AMTRAK). The revenue data for these two rates is set forth separately on Exhibit TPH-2, page A-5. The Company recommends Commission approval of these two new rates.

Q. Mr. Williams would you please explain the footnote regarding AMTRAK revenue as shown on page A-5 of Exhibit TPH-2.

A. The budgeted revenue for AMTRAK was based upon the demands historically billed with demand simultaneously measured at the frequency converter input supply points and the railroad interchange points at Perryville (Baltimore Gas and Electric) and Thorndale (Pennsylvania Power & Light). Subsequent to the preparation of the budget the Company finalized a new contractual agreement with AMTRAK which eliminated the railroad interchange points of Perryville and Thorndale from the demand calculation. The percent of revenue increase shown in column 11 on page A-5 is the actual percentage increase that will result under the new contractual demand calculation. The actual revenue increase proposed is $3,746,516 as calculated in the Company's response to 52 Pa. Code Section 53.53(IC C-1).

Q. Are there any other rate revisions in the filing?

A. Yes. We have revised Rate OP to more clearly set forth the two types of service offered. The service that is interrupted everyday has now been designated OP-1 and the service that is interrupted only five days a week and is not interrupted on Saturdays, Sundays or Holidays has been designated OP-2. There are now approximately 3,400 customers on Rate OP-2 and this restatement of the rate will provide greater flexibility to relate the off-peak times to high cost operating periods.

Q. Does that conclude your testimony at this time?

A. Yes.

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

UNRECOVERED REVENUE COLLECTION RIDER (C)

APPLICABILITY. This rider provides for the delay of the billing of part of the revenue otherwise due through application of Rates R, R-H, GS, PD, HT, EP-A, EP-S and BLI and the Transformer Rental Rider, and the subsequent recovery of this revenue.

TERMS. In accordance with the provisions of this rider, revenue collection will be partially delayed during the two years after the effective date of this rider. The base rate revenue to be billed to customers on this rider during each year after the effective date of the increase approved at Docket No. R-850152 shall be computed by use of the factors shown herein. The unrecovered revenues are the differences between the revenues due through application of the base rates and the billed base rate revenues. This revenue shall be recovered in a three-year period beginning with the end of the third year that this rider is in effect; however, this rider shall remain in effect until the unrecovered revenue account balances are zero for all applicable rates. The Unrecovered Revenue Collection Rider applies only to the timing of the billing of the rates as filed in this tariff supplement, and does not in any way affect the Company's right to recover and the Customer's obligation to pay the full amount of the rates as set forth in this tariff supplement.

OTHER PROVISIONS. In the event base rates are changed by action of the Pennsylvania Public Utility Commission from those reflected in the tariff supplement of which this rider was first a part, appropriate changes shall be made to this rider so that the effects on Customer billing will be substantially the same as those contemplated in the original rider.

UNRECOVERED REVENUE FACTORS. Unrecovered revenue factors are applied to each block of each rate schedule. The unrecovered revenue factors to be applied to each rate schedule for each of the six years are as follows:

RATE	Year 1	Year 2	Year 3	Years 4, 5 & 6
R				
Customer Charge	0.96421	0.98316	1.00000	1.01684
Energy Charge				
Summer				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.83589	0.91762	1.00000	1.08237
Winter	0.83994	0.91997	1.00000	1.08003
R-H				
Customer Charge	0.96421	0.98316	1.00000	1.01684
Energy Charge				
Summer				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.83589	0.91762	1.00000	1.08237
Winter				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.89362	0.94752	1.00000	1.05248
GS				
Without Demand Measurement				
Customer Charge				
Single-Phase	0.94500	0.97167	1.00000	1.02833
Polyphase	0.82780	0.91366	1.00000	1.08634
Energy Charge				
Block 1				
65 Hours' Use	0.83326	0.91642	1.00000	1.08358
15 Hours' Use	0.61578	0.80810	1.00000	1.19190
Block 2				
65 Hours' Use	0.93303	0.96652	1.00000	1.03348
15 Hours' Use	0.75023	0.87511	1.00000	1.12489
Block 3	0.90773	0.95386	1.00000	1.04614
Block 4	1.22957	1.11479	1.00000	0.88521

(C) Indicates change.

(Continued)

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

UNRECOVERED REVENUE COLLECTION RIDER-Continued (C)

RATE	Year 1	Year 2	Year 3	Years 4, 5 & 6
GS				
With Demand Measurement				
Customer Charge				
Single-Phase	0.94500	0.97167	1.00000	1.02833
Polyphase	0.82780	0.91366	1.00000	1.08634
Energy Charge				
Block 1				
65 Hours' Use	0.83326	0.91642	1.00000	1.08358
15 Hours' Use	0.61578	0.80810	1.00000	1.19190
Block 2				
65 Hours' Use	0.93303	0.96652	1.00000	1.03348
15 Hours' Use	0.75023	0.87511	1.00000	1.12489
Block 3	0.90773	0.95386	1.00000	1.04614
Block 4	1.14591	1.04864	1.00000	0.95136
Heating Block	0.89362	0.94752	1.00000	1.05248
PD				
Customer Charge	0.98308	0.99152	1.00000	1.00848
Capacity Charge	0.67554	0.83826	1.00000	1.16174
Energy Charge				
Block 1	0.88229	0.94166	1.00000	1.05834
Block 2	0.92330	0.96165	1.00000	1.03835
Block 3	1.02611	1.01305	1.00000	0.98695
HT				
Customer Charge	0.88972	0.94484	1.00000	1.05516
Capacity Charge	0.71292	0.85593	1.00000	1.14407
Energy Charge				
Block 1	0.84440	0.92220	1.00000	1.07780
Block 2	0.88772	0.94461	1.00000	1.05539
Block 3	1.00267	1.00000	1.00000	1.00000
BLI				
Energy Charge	0.85140	0.92606	1.00000	1.07394
EP-A				
Service Charge	0.35013	0.67506	1.00000	1.32493
Capacity Charge	0.56020	0.78010	1.00000	1.21990
Energy Charge				
Block 1	1.64800	1.32267	1.00000	0.67733
Block 2	1.32267	1.16000	1.00000	0.84000
Block 3	1.00000	1.00000	1.00000	1.00000
EP-S				
Service Charge	0.33675	0.66838	1.00000	1.33162
Capacity Charge	0.54492	0.77246	1.00000	1.22754
Energy Charge				
Block 1	1.64800	1.32267	1.00000	0.67733
Block 2	1.32267	1.16000	1.00000	0.84000
Block 3	1.00000	1.00000	1.00000	1.00000
Transformer Rental Rider				
Fixed Charge				
Block 1	0.85426	0.92704	1.00000	1.07296
Block 2	0.85569	0.92477	1.00000	1.07523
Operating Charge	0.84431	0.92216	1.00000	1.07784

(C) Indicates change.

PROCEDURES FOR DETERMINING RATE PRICING FOR PHASE-IN OF RATE INCREASE

A phase-in ratio will be computed for each rate block price for year 1 and for year 2 in accordance with the following procedure.

First Year

1. Determine the difference between the presently effective rate and the compliance filing rate by rate blocks. This difference will be the basis for the calculation of phase-in and phase-out ratios during the entire period that the Unrecovered Revenue Collection Rider is in effect.
2. Subtract 2/3's of the difference by rate blocks as calculated in step #1 to obtain the first year rate pricing.
3. Divide this first year rate pricing by the compliance filing rate pricing to obtain ratios for each rate block.
4. Calculate the base revenue portion of the customers bill using the full compliance filing rate.
5. Apply the ratios for each rate block calculated in step #3 to the bill calculation in step #4 to determine the base rate revenue to be billed to the customer.
6. Subtract the base rate revenue calculated in step #5 from the revenue calculated in step #4 to determine the amount to be placed in the Unrecovered revenue account.

Second Year

1. Subtract 1/3 of the difference by rate blocks as calculated in step #1 to obtain the second year rate pricing.
2. Divide this second year rate pricing by the compliance filing rate pricing to obtain ratios for each rate block.

3. Calculate the base revenue portion of the customers bill using the full compliance filing rate. ,

4. Apply the ratios for each rate block calculated in step #2 to the bill calculation in step #3 to determine the base rate revenue to be billed to the customer.

5. Subtract the base rate revenue calculated in step #4 from the revenue calculated in step #3 to determine the amount to be placed in the unrecovered revenue account.

<u>Third Year</u>

1. The full compliance filing rate increase will be put into effect therefore, the ratio will be 1.000 and there will be no revenue placed in the uncovered revenue account.

<u>Fourth Year</u>

1. Add 1/3 of the difference calculated in first year - step #1 to the compliance filing rate by rate blocks to obtain the fourth year rate pricing.

2. Divide this fourth year rate price by the compliance filing rate price to obtain a ratio for each rate block.

3. Calculate the base revenue portion of the customers bill using the compliance filing rate.

4. Apply the ratios for each rate block obtained in step #2 to the bill calculation in step #3 to determine the base rate revenue to be billed to the customer.

5. Subtract the base rate revenue calculated in step #3 from the revenue calculated in step #4 to determine the amount to be credited to the unrecovered revenue account.

At the end of the fourth year, the rate of revenue recovery will be adjusted if necessary to spread the remaining revenue to be recovered over the fifth and sixth years.

<u>Fifth and Sixth Years</u>

1. Same procedure as the fourth year unless adjustment is required as described above.

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9/24/85

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

DIRECT TESTIMONY

OF

THOMAS P. HILL, JR.

OVERVIEW OF RATE REQUEST;

EXPLANATION OF ACCOUNTING DATA AND

CERTAIN RATE BASE AND EXPENSE CLAIMS

September 1985

Direct Testimony of Thomas P. Hill, Jr.

Q. Please state your name and address for the record.

A. Thomas P. Hill, Jr., 2301 Market Street, Philadelphia, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am the Assistant Manager of the Rate Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I graduated with honors from Lehigh University in 1970 with a BS in Industrial Engineering. I also received my MBA from Lehigh University in 1974.

Q. Please outline your experience with Philadelphia Electric Company?

A. Following my graduation from college in 1970, I joined Philadelphia Electric Company as an Engineer in the Rate Division. I held this position until 1978 when I was appointed Supervisor of Tariff and Special Projects within the Rate Division. In March 1982 I was appointed Assistant Manager.

Q. Would you explain briefly your responsibilities in these assignments?

A. As an Engineer in the Rate Division, I worked in a variety of areas which have included economics and statistical analysis of Company operations. In conjunction with this work, I was an instructor, from 1976 to 1984, in the Company's Engineering Economics Course. My specific responsibilities as an Engineer included cost analyses, development of tariff pricings, and investigation of various rate forms for all resale and wholesale tariffs of the Company. I have worked extensively in the preparation of materials required for rate filings before the Pennsylvania Public Utility Commission, the Public Service Commission of Maryland, and the Federal Energy Regulatory Commission. In addition, I have worked on the design, filing, and implementation of both State and Federal Fuel Adjustment Clauses. Additionally, I have participated in development of the Plant Mortality Studies required for the determination of depreciation rates for all Company operations and the determination of depreciated plant in service.

As Supervisor of Tariff and Special Projects, I was responsible for the preparation of all rate filing requirements specified by regulations, the development and support, through testimony, of studies and exhibits as they relate to rate proceedings and the maintenance of actuarial data necessary to compute Company depreciation rates.

As Assistant Manager, I report to the Manager of the Rate Division and share with him the responsibilities that relate to the development of tariffs and rates on file with federal and state regulatory commissions, the preparation of all necessary supporting data, the administration of these tariffs and the completion of various studies as assigned by top management.

Q. What are your professional affiliations?

A. I have been a Registered Professional Engineer in Pennsylvania since 1975. From 1979 to 1982 I served as a member of the Edison Electric Institute Depreciation Accounting Committee. I have been a member of the American Gas Association Rate Committee since 1982. I am also a member of the Ad Hoc Rate Committee for the Pennsylvania Electric Association.

Q. Would you outline your prior experience in preparing rate filing materials and testimony given in rate proceedings?

A. I have participated in the preparation of rate cases and the preparation of exhibits for rate base, revenue, expense and other adjustments in prior electric operation filings which include: the 1975 Electric Rate Case (RID 295), the 1977 Electric Rate Case (RID 438), the 1979 Electric Rate Case (R- 79060865), the 1980 Electric Rate Case (R-80061225), the 1981 Electric Rate Case (R-811626), the 1982 Electric Rate Case (R-822291) and the 1984 Electric Rate Case (R-842590). At R- 79060865 I submitted testimony in the areas of nuclear fuel inventory, materials and supplies, land held for future use and non-revenue producing CWIP. At R-80061225, R-811626, R- 822291 and R-842590, I presented testimony on specific revenue adjustments, operating expenses and the Company's claimed rate base exclusive of depreciated plant in service.

I have participated in the preparation of all rate case materials in prior Gas Operations filings including the 1979 Gas Rate Case (R-79030781), the 1981 Gas Rate Case (R-811719), and the 1983 Gas Rate Case (R-832410). At R-79030781 I presented testimony as the Company depreciation witness responsible for claimed rate base and annual provisions for depreciation. At R-811719 and R-832410, I presented testimony in support of the Company's revenue claim, operating expenses and rate base exclusive of depreciated plant in service.

I have participated in the preparation of rate filing materials for the prior Steam Operations Filings including the 1979 Steam Rate Case (R-79040785), the 1980 Steam Rate Case (R-80071263), the 1981 Steam Rate Case (R-811720), the 1982 Steam Rate Case (R-822101) and 1983 Steam Rate Case (R-832434). At R-79040785, I presented testimony as the Company depreciation witness responsible for rate base and annual provisions for depreciation. At R-80071263, I presented testimony in support of the Company's claims for materials and supplies and cash working capital. At R-822101 and R-832434, I presented testimony supporting the Company's claims for all revenue and expenses.

In addition, I have prepared similar materials necessary for filing rate applications before the Federal Energy Regulatory Commission in support of our rate increases to the Borough of Lansdale and Conowingo Power Company. I have submitted testimony before the FERC at Dockets ER81-318, ER82-294, ER82-295 and ER84-9 and 10. I have also prepared rate filing material including rate base and all adjustments to rate base for filings before the Public Service Commission of Maryland for our subsidiary Conowingo Power Company.

Finally, I have submitted testimony in several Show Cause proceedings before the Pennsylvania Public Utility Commission. At Dockets No. P-830453 and No. M-840375, I testified on the administration of the Company's Energy Cost Rate and at Docket No. I-840381, I testified on the revenue requirements for Limerick Unit No. 2 and other alternate generation cases.

Q. What is the purpose of your testimony?

A. I will describe the major reasons why the Company is requesting a $670.7 million net base rate increase. I will explain the process of the development of the Company's original cost of plant in service and its book operating revenue and expense levels including various accounting statements as presented in my Exhibits. I will describe and support certain of the adjustments to operating revenues and expenses which have been made to place book levels on a proforma test year basis. I will explain and support the Company's rate base claim for Limerick 1 nuclear fuel assemblies in the reactor, and miscellaneous rate base deductions. Finally, I will describe the Company's revenue requirements associated with Limerick 1 and 100% of common facilities that are to be included in base rates, and the revenue impact of the retirement of Richmond Unit 9, Southwark Units 1 and 2 and miscellaneous combustion turbines.

Q. Please summarize the major factors which contribute to the rate increase requested by the Company in this proceeding.

A. The Company's claim reflects a net increase in Pennsylvania jurisdictional base electric operating revenues of $670.7 million. As explained in the Statement of Reasons submitted with this filing, this revenue increase is required (1) to permit the Company to recover the capital and operating costs of Limerick 1 offset by energy savings from this unit, (2) to reflect a net decrease in revenue requirements caused by life extensions of coal-fired generating facilities and sales increases offset by increased depreciation and operating and maintenance expense, and (3) to allow the Company's common equity investors an opportunity to earn a fair return on their investment. While the Company believes a fair return on common equity is 16.9% to 17.4% as developed by Company witness J. F. Brennan, we have designed rates that provide for only a 15.75% equity return.

Q. Please explain the derivation of the net $670.7 million requested revenue increase.

A. The net increase is comprised of two components: (1) an $878.2 million increase in rates to reflect additional plant in service and increased operating expenses, and (2) a $207.5 million rate decrease to reflect the reduction in energy costs occasioned by the operation of Limerick 1. These energy savings are reflected in this filing by a

7.505 mills/kwh reduction in the base rate cost of energy. A corresponding reduction in the base cost of energy in the Company's Energy Cost Rate ("ECR") will be filed to become effective coincident with the effective date of Supplement No. 15. To the extent that actual energy savings from Limerick 1 are more or less than projected, this difference will be refunded or recouped in subsequent ECR filings.

Q. Please explain the specific rate impact of Limerick 1.

A. A principal reason for this rate filing is to reflect the capital and operating costs and energy savings associated with Limerick 1. Table 1 to this testimony details these costs and savings. As set forth therein, the net rate impact of Limerick 1 is $742.0 million, consisting of $949.5 million in capital and operating costs and $207.5 million in anticipated energy savings.

Q. Mr. Hill, will you be sponsoring any exhibits in this proceeding?

A. Yes, I will sponsor four exhibits prepared for use in this proceeding. The first two, Exhibits TPH-1 and TPH-2, contain the revenue, expense and rate base accounting data for the Company's historic and future test years. Although I am primarily responsible for the development of these exhibits and administered their preparation, I have not prepared and do not support all of the information in these documents.

There are two additional Company exhibits which I sponsor. First, I administered the preparation of responses to the Commission filing regulations contained in PECo Exhibit 1, but as with the Exhibits TPH-1 and TPH-2, I share substantive responsibility with other Company witnesses for the specific data set forth therein. I am responsible for that portion of the data which relates to the substantive area discussed in my testimony. I did not participate in the preparation of PECo Exhibit 2, which provides an explanation of the reasons for Limerick cost and schedule growth, as this document was developed by Company witnesses Boyer, Kemper, Clarey, Helwig, Sproat, Kononetz, Mattson and Love. Their testimony describes and supports its contents. The statement of reasons contained in PECo Exhibit 3 was prepared in order to provide a succinct summary of all areas of the Company's case for inclusion in the record. I have participated in the preparation and review of this document.

Q. Please describe the accounting data which you have prepared to support Supplement No. 15 to Tariff Electric--Pa. PUC No. 26.

A. In support of Supplement No. 15, we have provided Exhibit TPH-1, based on an historic test year ended June 30, 1985, which reflects data from the Company's actual books of account. We have also provided Exhibit TPH-2 based on the future test year ended June 30, 1986, which reflects data drawn from the Company's 1985 and 1986 Budgets. Mr. Albert J. Solecki will discuss in greater detail the Company's budget process, which provides the major source of information necessary to construct Exhibit TPH-2.

Q. Are you responsible for the information contained in Exhibits TPH-1 and TPH-2?

A. Yes, I am, to the extent I have previously described.

Q. Mr. Hill, will you be explaining all the material which appears in these Exhibits?

A. No. I will explain certain items related to the Company's rate base, and revenue and expense claims. As to certain plant and expense adjustments, I will explain the accounting of the adjustment while other witnesses will address the technical subject matter. Certain portions of Exhibits TPH-1 and TPH-2 will be explained entirely by other Company witnesses. I will note in my testimony where other witnesses are responsible for data presented in Exhibits TPH-1 and TPH-2. These same witnesses are responsible for these same subject areas in PECo Exhibit No. 1.

My testimony will concentrate on Exhibit TPH-2, but I will also explain any significant differences between Exhibit TPH-2 and Exhibit TPH-1. I should also note that Exhibit TPH-1 is presented solely for informational purposes and to comply with Commission regulations. The Company has not attempted to adjust the historic test year data to provide a fully accurate assessment of the Company's revenue requirement.

Q. Would you please describe Exhibit TPH-2, noting significant differences between it and Exhibit TPH-1.

A. Exhibit TPH-2 contains four sections:

Section A presents the summary Tables of Income Available for Return, Measure of Value, Adjustments to Income Available for Return, and Kilowatt-hour Sales and Revenue by Tariff Subdivisions;

Section B contains basic accounting information from the Company's records;

Section C contains data relating to the Measure of Value; and Section D shows details of adjustments to Revenues and Expenses.

Q. Please explain your development of the Company's income available for return under present rates for the test year ended June 30, 1986.

A. We have shown this on page A-1 of Exhibit TPH-2. As indicated on that page, our electric operating income under present rates for the June 30, 1986 test year after all adjustments to a proforma ratemaking basis is $444,781,000. This represents a rate of return of 6.39% on the claimed original cost Measure of Value of $6,963,532,000.

Q. Mr. Hill, I note on page A-1 of Exhibit TPH-2 that total additional operating revenues requested in Supplement 15 equal $681,760,000 and that the estimated fuel savings for Limerick 1 operation are $206,990,000. Why do these numbers differ from figures previously cited (i.e. at page 6) in your testimony?

A. These figures differ because they reflect the annualized sales level at the end of the future test year as shown on page A-5 of Exhibit TPH-2 (i.e. adjustment D-3). I have not used these figures because they are inconsistent with the Company's rate phase-in proposal and were not used in notifying customers of the requested rate increase. For these purposes, we selected to use the total rate increase and fuel savings associated with future test year sales (i.e. not annualized) as a more reasonable valuation of the effects of the proposed increase upon the average customer.

Q. Please discuss the schedules shown in Section A of Exhibits TPH-1 and TPH-2 in sequence including any explanations you consider necessary.

A. <u>Page A-1</u> presents the income available for return and the rate of return at the present and proposed rate levels. Actual TPH-1 or budgeted TPH-2 revenue, expenses, and income were taken directly from the Electric Operating Income Statement shown on page B-9 of the respective Exhibits and were adjusted for the items shown on page A-3 to derive the proforma income at present rates. The proforma income at present rates was then adjusted to reflect the higher rates of Supplement No. 15 to derive the operating income available for return under the proposed rates.

<u>Page A-2</u> shows the Measure of Value of electric plant at original cost. The numbers used in development of the measure of value are referenced and will be explained more fully in the discussion of Sections B and C.

The Company has reduced rate base by all accumulated deferred income taxes associated with accelerated amortization of property and liberalized depreciation on plant in service. Customer Deposits and Customer Advances, which are supplied by ratepayers, are also eliminated from the rate base calculation.

Page A-3 lists the 21 adjustments we have made to income for return. The first 20 adjustments increase income by approximately $16.8 million in the June 30, 1986 test year. The details of each adjustment are included in Section D. The last adjustment, shown on page D-21, reflects reductions in energy expenses resulting from the inclusion of Limerick Unit No. 1 in rates to serve Pennsylvania jurisdictional customers. This adjustment reduces revenue requirements to customers but has no effect on operating income for PECo. I will discuss this adjustment in further detail in the Section D portion of my testimony.

Page A-4 indicates the effect on income for return of Supplement No. 15 and highlights the associated fuel savings from the inclusion of Limerick Unit No. 1 in rates.

Page A-5 shows the number of customers, kwh sales, revenue and revenue increases by tariff subdivisions.

Q. Turning to Section B, please discuss its contents.

A. Section B information in Exhibit TPH-1 was taken directly from the Company's actual accounting records. The data in Exhibit TPH-2 for the specific 12-month period ended June 30, 1986 is taken from the Company's 1985 and 1986 budgets.

Q. Please continue the presentation of Section B with a page-by-page discussion of its contents.

A. Pages B-1 and B-2 of Exhibit TPH-2 represent the Company's estimated balance sheet at June 30, 1986.

Pages B-3 through B-6 show the original cost by plant accounts at test year end of the Company's electric plant and common utility plant, a portion of which is allocated to electric service by the allocation factor developed on page B-17. Mr. Smith is available to explain the Company's accounting procedures used in the development of plant in service.

Page B-7 displays the book reserve for depreciation for the Company's electric plant and electric portion of common plant. Mr. Wroblewski is available to explain the Company's accounting procedures used in the development of its book reserve for depreciation.

Page B-8 shows the consolidated income statement for the Company and its subsidiaries.

Page B-9 presents the operating income statement for the Company's electric operations.

Pages B-10 through B-14 show by primary accounts the expense items for electric operations. I am responsible for preparation of these schedules and for the explanation of historic versus test year claimed expense levels, except in the case of production plant expenditures explained by Mr. Carroll, depreciation explained by Mr. Wroblewski, taxes explained by Mr. Sileo, and nuclear decommissioning and spent nuclear fuel disposal explained by Mr. Wright.

Pages B-15 and B-16 show the computation of federal income tax and the development of electric operations share of the rate base adjustment for accumulated deferred taxes. Mr. Sileo is available to explain and support the Company's claimed income tax expense.

Page B-17 develops the factors for allocating common utility plant to electric operations. The allocation of the common plant in each Exhibit was made on the basis of the estimated plant investment, revenue, and customers at June 30, 1986 for each type of service.

Page B-18 shows the calculation of the effective income tax rate which is supported by Mr. Sileo.

Pages B-19 and B-20 list the Company's long-term debt and preferred stock outstanding and develops the associated embedded cost for each test year period. Mr. Brennan will explain the development of the Company's embedded cost of long-term debt and preferred stock.

Q. Will you now turn to Section C, the next section of your Exhibits, and explain what is covered there?

A. This section provides the detailed development of the major components that make up the measure of value shown on page A-2.

Q. How do you determine that all plant reflected in the claimed measures of value is used and useful?

A. The Company maintains a detailed system of capital authorizations, covering plant additions and retirements, under which any unit permanently taken out of service is recorded in the field and that information is transmitted to the Plant Accounting Division where the necessary retirement accounting entry is made. Most retirements occur in connection with a capital improvement project, which supplants the units retired, so that the retirement work order is usually part of a construction authorization. Maps and operating records maintained by the field operating forces provide a running record of physical facilities in service and Plant Accounting Division maintains a cross-check through their related financial records. Our Internal Auditing Division periodically reviews both plant accounting and operating records for accuracy and to insure that changes in property are properly reflected in the accounts.

Page C-1 contains a general description of the Company's claimed measure of value.

Pages C-2 and C-3 summarize by plant groupings the utility plant in service for each test year showing both the original cost and book depreciation reserve. Mr. Smith explains the Company's accounting procedures and the FERC and PaPUC audits which assure that all property contained within these accounts is in fact in service.

Page C-4 provides a description of annual and accrued depreciation and amortization calculations used in the determination of measure of value. Mr. Wroblewski's testimony explains the basis of these annual depreciation calculations and also the development of the book depreciation reserve.

<u>Pages C-5 through C-6</u> summarize the annual provision for depreciation.

<u>Page C-7</u> provides the terminal dates for production plant utilized under the remaining life method of depreciation. The establishment of these dates will be explained by Mr. Rush.

<u>Page C-8</u> develops the Company's claim for non-revenue producing construction work in progress. This schedule will be discussed by Mr. Wright.

<u>Page C-9</u> lists land held for future use. This schedule also will be explained by Mr. Wright.

<u>Page C-10</u> displays the Company's claim for Electric Operation's materials and supplies. This schedule will be explained by Mr. Carroll and Mr. Wright.

<u>Page C-11</u> reflects the Company's investment associated with Limerick Unit No. 1 in Account 120.3, Nuclear Fuel Assemblies in Reactor. This investment is reflected in Account 120.3 in conformance with the requirements of the Federal Energy Regulatory Commission's Uniform System of accounts which states as follows:

> "This account shall include the cost of nuclear fuel assemblies when inserted in a reactor for the production of electricity."

Since this nuclear fuel investment is essential for the operation of the plant, it is proper that a normalized level of investment be included in the Company's rate base claim.

Unlike Salem and Peach Bottom fuel which are leased, Limerick Unit No. 1 fuel is owned by the Company. Lease payments provide for both elements of capital recovery, a recovery of investment and a return on investment. For Limerick Unit No. 1, recovery of the investment in nuclear fuel occurs through the Energy Cost Rate as the fuel is consumed. In order to provide for a return on invested capital, rate base inclusion is necessary. A similar claim made by the Company for its Salem Unit No. 1 nuclear fuel investment (prior to its current lease arrangement) was found to be reasonable and was accepted by this Commission in its orders at RID 438 and R-79060865.

The period March 1986 to March 1988 was used to develop the nuclear fuel in reactor claim for several reasons. First, since Limerick is scheduled for commercial operation beginning February 15, 1986, the use of the test year average or year end balance would overstate the claim as it is not representative of a normal period of operation. Second, the period chosen includes a refueling outage which is part of the normal operation of the plant. Use of a one-year period would exclude any refueling outage and understate the average amount of nuclear fuel in reactor. Finally, the two-year average properly reflects the anticipated period rates established in this proceeding will be in effect.

<u>Page C-12</u> details the levels and requirements for cash working capital at the historic and future test year ends. This schedule will be explained by Mr. Wright.

Q. Would you please explain Section D of your Exhibits?

A. Section D contains the adjustments required to place budgeted or actual operating revenues and expenses on a normalized, year end ratemaking basis in conformance with prior Commission rulings. These detailed adjustments are summarized on pages A-3 and A-4 of the Exhibits and then carried forward to page A-1 to derive proforma operating income at both present and proposed rates.

Q. Please describe the review you performed to determine that the Company's claimed revenues and expenses are "normal" and thus properly claimed for recovery during future periods?

A. There are several steps involved in my review of the future test year claim. First, I compare the budgeted revenues and expenses in the future test year versus those in the historic test year and preceding years. Next, I review any significant changes as shown in filing interrogatory II-D-1 or as developed from my first analysis described above with the responsible individuals to determine reasons for the changes and whether amounts should be included in the test year, excluded from the test year or whether any amortizations or normalization adjustments are necessary. I am specifically responsible for performing this review, i.e. to assure that claimed revenue and expense levels are "normal" and therefore a proper claim, for (1) transmission and distribution expenses, (2) customer accounts, (3) customers service and informational expense (4) sales expense, and (5) administrative and general expenses. Mr. Carroll is responsible for performing this review for production expenses, Mr. Sileo is responsible for taxes and Mr. Wroblewski is responsible for depreciation. Third, I review with the appropriate divisions and departments data contained in my accounting exhibits and related filing interrogatories to assure that none of this data suggests the need for further adjustment. In conducting these reviews, I consider the effects of the D Schedule adjustments and rely upon my knowledge and that of the responsible technical managers of the contents of these expenses and of major Company or department actions that affect their "normalcy".

Q. Please discuss the Section D schedules in sequence including any explanations you consider necessary.

A. The adjustment on <u>Page D-1</u> eliminates the state taxes covered by the State Tax Adjustment Clause (STAC) and an amount of revenue equal to those taxes. There is no net effect on income available for return because equal dollars of revenue and taxes are removed. Mr. Sileo will support this adjustment.

<u>Page D-2</u> reflects the full year revenue effect of Tariff No. 26, Supplement 11, which became effective January 25, 1985. This adjustment is applicable only to

the historic test year. Mr. Wright will discuss this adjustment.

Q. Please describe the Company's adjustment shown on page D-3 of the Accounting Exhibits.

A. Page D-3 summarizes the effects on annual revenues, expenses, income taxes and operating income to reflect the annualization to test year end levels for (1) customers added during the test year periods, and (2) the growth/decline in usage of existing customers. The methodology utilized by the Company in this adjustment is exactly the same as that previously accepted by the Commission most recently in its Order at R-842590. This methodology is shown on pages D-3a and D-3b of Exhibits TPH-1 and TPH-2.

Page D-3a of Exhibits TPH-1 and TPH-2 shows the three year average annual growth for residential, house heating, small commercial and large industrial customers. One half of this average annual growth is multiplied by the number of customers on the system at the beginning of the test year to yield the increased/decreased usage in kilowatt-hours. This is based on the assumption that growth was uniform throughout the test year so that annualization is required for the remaining one-half of the test year. This increased/decreased usage due to growth of existing customers is then multiplied by the average base revenue for each class of customers as obtained from page A-5.

Also shown on page D-3a is a summary of the annualization of usage of customers added during the year. It is estimated that these customers were added uniformly throughout the year so that the annualization is required for the remaining one-half of the test year usage of the new customers. Therefore, one-half of the number of customers added during the test year is multiplied by the average use per customer in each rate classification during the test year to obtain the increased/decreased sales in kilowatt-hours that would result from these new customers had they been served for a full 12 months. The increased/decreased sales in kilowatt-hours are multiplied by the average base revenue obtained from page A-5 to yield the increased/decreased revenue due to this annualization of new customer usage.

An increase in operating expenses resulting from the increase in sales developed on page D-3 could consist of fuel costs as well as other incremental operation and maintenance costs such as incremental production costs other than fuel, distribution expenses and customer-related costs. In order to be conservative in its claim, the Company has included only the increase in base fuel expense, as defined by the Energy Cost Rate, for this adjustment.

The net increase in revenue resulting from the adjustment for each period is carried forward to D-3 where after deduction of the 2% Gross Receipts Tax, the increase in operating expenses and the increase in income taxes, the net increase in income for return is shown.

Page D-4 eliminates from the test year data the revenues and expenses covered by the energy cost rate (ECR). For the test year ended June 30, 1986, the Electric Energy Cost Rate revenue including the 4.5% Gross Receipts tax is ($53,711,000). This revenue is removed from the test year. The total energy cost allocated to Philadelphia Electric Company Electric Operations for the 12 months ended June 30, 1986 is $509,710,000 of which ($218,208,000) was deferred so that the net fuel and interchanged expense for the year is $727,918,000. The portion of this fuel expense recovered in base rates is $779,209,000 so that the net fuel expense to be removed is ($51,291,000).

When the Gross Receipts Tax of ($2,420,000) is added to the fuel expense of ($51,291,000) the total expense removed is ($53,711,000) which is exactly equal to the fuel revenue to be removed. There is no effect on income for return.

The same methodology was used for the D-4 adjustment included in Exhibit TPH-1.

Page D-5 presents the Company's annualization of wage rates, benefits and number of employees for each of the test years. This adjustment in the historic test year shown in Exhibit TPH-1 adjusts historic labor expenses to annualize for known increases in wages and benefits. Actual regular payroll data for June 1985, as set forth on page D-5a, is initially annualized to reflect the wage increase which became effective on August 1, 1984. The resulting figure is then further adjusted for the August 1, 1985 wage increase of 5.4%. The 12-month average overtime percentage experienced during the historic test year of 17.5% is then applied to the increase in regular payroll costs. Finally, comparable adjustments are made to annualize for the effect of increased pensions and employee benefits included in the actual August 1, 1984 and August 1, 1985 wage packages. The total annual costs of these changes are developed for combined operations and that portion allocated to Electric Operations is determined.

A similar adjustment is set forth on page D-5 of Exhibit TPH-2 to annualize increased wages and employee benefits effective August 1, 1985 and not fully reflected in the test year data. The overtime percentage of 12.2% for the future test year is based on the June 30, 1986 budget data (page D-5a). Similar adjustments to those described above for the historic test year are made for pensions and benefits.

The Company, in previous electric rate proceedings, has included an adjustment for the effect of the wage increase that would occur during the time period new rates are in effect. Although the Company still supports this position, in this particular proceeding, the Company will not claim future wage and benefit increase expenses.

<u>Page D-6</u> adjusts the annual depreciation expense to a

ratemaking basis reflecting the test-year end plant in service. Mr. Wroblewski is responsible for the technical depreciation and salvage aspects of this schedule.

Page D-7 develops the change in income available for return due to the change in taxes resulting from the computation of tax depreciation and amortization on the basis of year-end plant in service.

Page D-8 develops the change in income available for return from the normalization of tax deferrals on year-end plant and elimination of tax deferrals reflected on D-1.

Page D-9 shows the calculation of the adjustment to income taxes resulting from the allocation of proforma interest charges based on the Company's rate base at the end of the test year. Mr. Sileo is available to discuss pages D-7 through D-9 in greater detail.

Page D-10 adjusts nuclear and fossil plant production operating and maintenance expenses to reflect a normalized level of expenses for ratemaking purposes. Mr. Carroll will discuss these expense adjustments.

Page D-11 eliminates from budgeted operation and maintenance expense all expenses associated with production plant that is being retired. Mr. Carroll will explain this adjustment.

In addition, Table 2 attached to this testimony details the revenue requirement impact associated with these retirements. As set forth therein, the impact of these retirements is a revenue reduction of $11,491,000.

Page D-12 shows the adjustment of book expenses to reflect the amortization of certain types of expenses provided for in prior rate proceedings. Detailed supporting data is set forth on page D-12a. Previously approved amortizations include rate case expenses, turbine lease cancellation, storm damage expenses, office automation equipment expenses, abandoned engineering at Chester Station, Eddystone Unit No. 1 restoration expenses, deferred taxes - State Tax Rate Change and the Pioneer Uravan amortization. Each of these items was approved in the Company's most recent electric proceeding at Docket No. R-842590. The claimed amounts are based on the amortization periods adopted by the Commission.

The Company is also claiming a two-year amortization of rate case expenses associated with the current rate proceeding and the ECR #9 investigation. This two-year amortization period was chosen to be consistent with the proposed period of time between rate cases. The rate case amortization claimed for the current proceedings is $1,340,000. The amortization claim for the ECR #9 related expense is $300,000. The Company is claiming a $1,100,000 amortization for expenses associated with the current Limerick Unit #2 Show Cause investigation. In an effort to minimize the Company's test year expense claim, and still provide for recovery of this expense, a five-year amortization was chosen for this item. In addition, it was felt that investigations of this type, while occurring periodically, will not occur with the same regularity as standard rate proceedings. Details of rate case and other PaPUC investigation related expenses are provided in response to Commission's filing requirement (II-D-6).

Finally, the Company is claiming a five-year amortization of the $445,000 representing abandoned engineering charges associated with the Heaton-Byberry Transmission Line. This project has been dropped from the Company's 1985-1993 construction forecast and there are no plans to construct the transmission line. The five-year amortization period was used to be consistent with the Commission's Order in R-801225 where Chester Station abandoned engineering was amortized over five years.

Page D-13 shows the adjustment to eliminate revenue and the fuel expense associated with sales to the Borough of Lansdale. Mr. Wright will explain this adjustment.

Page D-14 shows the adjustment to recognize changes in Federal Social Security Tax Laws. Mr. Sileo is available to explain this adjustment.

Page D-15 shows the adjustment for the cost of decommissioning the Company's nuclear units at Peach Bottom, Salem, and Limerick. Mr. Wright and Dr. McCleod will explain this adjustment.

Page D-16 shows the adjustment to include in the test year operating expenses the Company's cost of spent fuel removal based on the terms set forth in the Nuclear Waste Policy Act. Mr. Wright will explain this adjustment.

Page D-17 provides the Company's claim to recover its investment in certain Salem Unit No. 1 nuclear fuel assemblies which were denied recovery through the Company's Energy Cost Rate mechanism. The investment is associated with fuel assemblies that sustained grid strap (fuel assembly binding) damage during a scheduled refueling outage. The Pennsylvania Public Utility Commission Audit report on the Energy Cost Rate for the year ended December 31, 1982 disclosed that the cost of the damaged fuel assemblies were legitimate costs of doing business but the ECR was not the appropriate recovery mechanism. The audit report states that a more appropriate form of recovery would be a base rate proceeding and therefore we are claiming the expenses in this case.

The expense associated with the damaged nuclear fuel assemblies, while not a normal annual operating expense, is an expense that can occur periodically. Since it is not a normal annual operating expense, it is not reflected in the Company's budgeted expenses, and therefore, expenses such as this can only be recovered through an amortization such as that requested. A three-year amortization was selected based on the Commission ordering a three-year amortization of a deferred fuel adjustment in R-801225.

Page D-18 reflects the full-year effect of the operating and maintenance, pensions and benefits, insurance expenses and payroll taxes associated with Limerick Unit 1. All of the budgeted non-fuel production operation and maintenance expenses, pensions and benefits, insurance and payroll taxes for Limerick No. 1 unit were deferred under the provisions of the Commission Declaratory Order (P-840514). Consequently, this adjustment is required in order to reflect the proper level of test year expenses for Limerick #1. The Limerick pensions, benefits and payroll taxes utilized are based on the estimated Limerick wage costs and the relationship of direct wage costs and pensions, benefits and payroll taxes for Peach Bottom. The insurance expense is the full-year effect of the property and liability coverage that was deferred for budget purposes. Property insurance was based on an allocation of the total Limerick property insurance to Limerick Unit #1 and common. The allocation is based on insurable value. Liability insurance is a fixed rate per nuclear unit. Mr. Carroll will provide a detailed explanation of the nuclear production operating and maintenance expense adjustment. Mr. Cotton describes the specific activities at Limerick which are funded by these expenditures.

<u>Page D-19</u> adds in the additional income which would result if the requested system average rate of return was obtained from non-Pennsylvania jurisdictional customers. The Company's cost of service study WFS-1 shows that the current rate of return from the FERC jurisdictional sales and the interdepartmental sales is lower than the overall average Company rate of return sought in this case. This adjustment increases Philadelphia Electric Company's income

for return by $5,526,000. Since this adjustment is based on the Pennsylvania jurisdictional return level, it should be adjusted to reflect the revenue level granted by the Commission in its final order.

A similar adjustment done in exactly the same manner is shown on page D-19 of Exhibit TPH-1 and yields a similar increase in income for return.

Page D-20 reflects a full-year's amortization of utilized investment tax credit on qualifying plant placed in service during the test year. The effect of the adjustment is to place the ITC amortization on a year-end basis. Mr. Sileo will provide a detailed explanation of this adjustment.

Page D-21 adjusts the Company's energy costs to reflect the savings anticipated from the operation of Limerick 1. Specifically, the Company has reduced the cost of energy reflected in base rates by 7.505 mills per kilowatt-hour to reflect energy savings anticipated from the normalized operation of Limerick 1. This net effect is summarized on pages A-4 and A-5 of Exhibit TPH-2. Mr. Carroll will explain the derivation of the reduction calculated on Page D-21.

Q. Mr. Hill, are you aware of the Commission's Order at Docket C-78080459, entered on September 4, 1985, which requires as part of a rate case the filing of certain data and compliance with certain requirements related to the Company's lobbying and certain other activities?

A. Yes, I am.

Q. Has the Company, in the present rate filing, filed the data or complied with the requirements specified by the Order?

A. Not entirely. In preparing the materials filed in this case, the Company did not have sufficient time to respond to all of the additional requirements set forth in the Commission's Order. However, the Company will provide the Commission and all parties of record to this proceeding with an analysis of the matters addressed in the Commission's Order by November 1, 1985.

Q. Does that complete your testimony at this time?

A. Yes.

1932T/76M

Limerick Revenue Requirements
(Thousand $)

Exhibit TPH-2 Reference				
	Capital Costs			
C-2	Utility Plant in Service	$3,820,000		
C-2	Book Reserve	(38,665)		
C-10	Materials and Supplies	(4,447)		
C-11	Nuclear Fuel in Reactor	82,252		
C-12	Cash Working Capital	6,254		
C-12	Interest and Preferred Dividend Payment Offsets	(19,440)		
B-16	Liberalized Depreciation on Plant in Service	(135,585)		
	Total Measure of Value	$3,710,369 x 20.23%(a)		$750,608
C-5	Book Depreciation $102,737/(1-T)/(1-GRT)			208,699
D-7a	Tax Depreciation $262,069 x T = $130,426/[(1-T)x(1-GRT)]			(264,947)
D-8a	Excess Tax Depreciation $202,796 x FT = $93,286/[(1-T)x(1-GRT)]			189,501
D-20	ITC Amortization $10,313 + 2,334(b) = $12,647/[(1-T)x(1-GRT)]			(25,691)
	Total Revenue Requirements for Capital			$858,170
	Less Non Jurisdictional Customers			9,372(c)
	Total Revenue Requirements for Capital - Pa. Jurisdictional			$848,798
	Operating Costs			
D-10a	Outage Expenses		13,506	
D-15	Decommissioning Cost		3,253	
D-16	Spent Fuel Cost		6,247	
D-18	Operating and Maintenance Costs		75,740	
	Operating Cost		$98,746	
	Gross Receipts Tax		2,015	
	Total Operating Cost			$100,761
	Total Revenue Requirement			$949,559
D-21	Less: Fuel Savings - PA Jurisdiciton			207,537
	Net Revenue Requirement			$742,022

(a) Rate of Return Component

	Capitalization	Cost	Wtd Cost	PreTax Rev Req
Debt	50.7	10.84	5.50	5.50
Preferred	10.8	10.54	1.14/ (1-T)	2.27
Common Equity	38.5	15.75	6.06/ (1-T)	12.06
	100.0			19.83/(1-GRT)=20.23%

(b) Limerick Amortization reflected in 1985 budget

Note: T = Effective Tax Rate @ 49.768% (B-18)
GRT = Gross Receipts Tax Rate @ 2% (A-4)
FT = Statutory Federal Tax Rate @ 46% (B-18)

(c) Reflects only portion associated with Limerick Unit #1 and 100% common

Southwark, Richmond and Miscellaneous
Combustion Turbine Revenue Requirement
(Thousand $)

Capital Costs			
Utility Plant in Service			
Land	($2,389)		
Depreciable Plant	(104,308)		
Total	($106,697)		
Less Book Reserve	(104,308)		
Net Plant	($2,389)		
Materials and Supplies	(500)		
Cash Working Capital	(729)		
Total Revenue Reduction A/C Measure of Value	($3,618) x	20.23%(a) =	($732)
Less: Non Jurisdictional Customers			(12)
Total Net Revenue Requirement for Capital			($720)
Operating Costs			
D-11 Test Year Operating and Maintenance Cost (excluding fuel)			($10,556)
Gross Receipts Tax @ 2%			(215)
Total Operating Cost			($10,771)
Total Reduction in Revenue Requirements			($11,491)

(a) Rate of Return Component

	Capitalization	Cost	Wtd Cost	PreTax Rev Req
Debt	50.7	10.84	5.50	5.50
Preferred	10.8	10.54	1.14/ (1-T)	2.27
Common Equity	38.5	15.75	6.06/ (1-T)	12.06
	100.0			19.83/ (1-GRT)=20.23%

ORIGINAL

PECo Statement No. 19

RECEIVED

SEP 27 1985

SECRETARY'S OFFICE
Public Utility Commission

Pennsylvania Public Utility Commission

v.

Philadelphia Electric Company

Docket No. R-850152

Direct Testimony

of

Albert J. Solecki

Explanation of the Budget Process

and Inflation Rate Assumptions

September 1985

DOCKETED

SEP 27 1985

Direct Testimony of Albert J. Solecki

Q. Please state your name and address for the record?

A. Albert J. Solecki, 2301 Market Street, Philadelphia, PA 19101.

Q. By whom are you employed and in what capacity?

A. I am Manager of the Budget and Control Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I was graduated from LaSalle College in 1964 with a Bachelor of Science Degree in Accounting and in 1967 I received a Master of Business Administration from Drexel University. I also attended the Pennsylvania State University Executive Management Program from which I received a diploma.

Q. Please describe your employment experience with Philadelphia Electric Company?

A. I joined Philadelphia Electric Company in the Customers Accounts Division of the Finance and Accounting Department in 1958. In 1960, I joined the newly formed Electronic Computer Division as a Programmer working in the areas of computer system analysis and programming. In 1965, this division merged with the Systems Division. From 1965 to 1970 I held non-supervisory positions in the Systems Division in the areas previously mentioned. In 1971, I was appointed General Supervisor of the Systems Division; in 1972, I was named Assistant Manager, Systems Division. In 1973, I was appointed Assistant Manager of the Financial Division and in 1977, I was named Manager of that Division having responsibility for the development and execution of long term financing plans, including regulatory filings, investor relations and economic analyses. In May 1978, I was appointed Manager of Taxes Division, with responsibility for tax planning and research, collection and preparation of tax accounting data, preparation and filing of tax returns and settlement of tax returns and claims. In July 1980, I was appointed Manager of the Budget and Control Division.

Q. Have you been active in any professional organizations?

A. From 1971 to 1973, I was a member of the Methods and Computer Services Committee of the Edison Electric Institute. From 1973 to 1978, I was a member of the Statistical Committee of the Edison Electric Institute serving as Chairman of this Committee's Financial Ratios Group for 1977 and 1978. From 1978 to 1980, I was a member of the Tax Committee of the Edison Electric Institute. At present, I am Chairman of the Budgeting and Financial Forecasting Committee of the Edison Electric Institute. The Budgeting and Financial Forecasting Committee has responsibility for studying budgeting and financial forecasting in the utility industry; for the development of improved budgeting and financial forecasting techniques; for the development of effective tools for budgetary control and for encouraging the use of budgets and financial forecasts as aids in decision making.

Q. What are the responsibilities of the Budget and Control Division?

A. The Budget and Control Division is responsible for the coordination, preparation and analysis of the corporate operating budget and forecast; the analysis of financial performance and preparation of related internal and external reports; analyses and various other activities related to the measurement and control of Company costs; and preparation and maintenance of corporate procedures and forms design and control.

Q. Please describe in greater detail your activities as Manager of Budget and Control.

A. I have overall responsibility for the coordination, preparation and analysis of the Company's operating budget and forecast. Under my direction, the necessary budget and forecast data is coordinated, processed, reviewed and presented to management for approval. I participate in budget and forecast reviews at all levels in the organization. In addition, my responsibilities include the development and implementation of budget and forecasting systems designed to aid in the analysis of budget and forecast data as well as the presentation of such data to management. Under my direction, analyses of actual results relative to budget are also performed and presented to management on a monthly basis. In the non-budget related areas, I have responsibility for corporate procedures, forms analysis and design, the performance of special studies as requested by management and the preparation of various external financial reports.

Q. Have you testified in any previous proceedings?

A. Yes. I have presented testimony before the Pennsylvania Commission as to tax matters in the proceeding at R-79030781 involving a gas rate increase request, at R-79040785 involving a steam rate increase request, and at R-79060865 and R-800611225 involving the Company's requests for electric rate increases. I have also presented testimony before the Pennsylvania Commission as to the Company's accounting procedures and budget process in the proceedings at R-822291 and R-842590 involving the Company's requests for electric rate increases.

Q. What is the purpose of your testimony?

A. I will describe the Company's budget process and the inflation rate assumptions used in the preparation of the 1985-86 budget.

Q. Please explain the Company's budget process.

A. Each year a detailed 24 month budget is prepared as a tool for managing and conducting the operations of the Company. This budget is prepared on a "responsibility basis". That is, following the Company's organization chart, specific responsibility areas are defined and each area then budgets those items which fall within their responsibility.

The budgeting process begins with the development of objectives, initial personnel requirements and assumptions and guidelines such as service dates for new units, retirements of old units, and inflation factors. These assumptions and guidelines in the form of an instruction letter are sent to each of the approximately 165 responsibility areas. Each area reviews its historic expense levels and significant events which will alter those levels, known cost changes and guidelines set forth in the instruction letter and develops their segment of the budget. Inflation factors which were 5.25% for 1985 and 6.4% for 1986 are only used where specific known cost changes are not available and the level of activity being budgeted is expected to remain essentially unchanged, except for inflation.

The completed responsibility budgets are reviewed by my staff in order to develop the overall Company budget. The budget is then presented to the Chairman of the Board and the President for their review and for submission to the Board of Directors for their final approval. The budget process is usually completed and approved in January.

Once established, the budget is very rarely changed. As the year progresses, actual results as compared with budget are monitored on a monthly basis and an informal projection of the remainder of the year, starting with the budget and adjusting for significant known changes, is made.

Q. Please explain in more detail the organization and mechanics of the budget process.

A. To facilitate communications with my staff and the overall budget processing and review functions, budget coordinators are established for each of the departments in the Company. A budget coordinator is an employee of the operating department and has primary responsibility for the coordination and review of budget information for the responsibility areas in his department.

The budget system is a state of the art, on-line computer system which utilizes video display terminals for budget submissions and provides immediate feed-back to the individual submitting the budget, including variance messages as soon as the budget data for an account is submitted. In the case of a variance, an explanation for the variance must be provided before the budget data for the account being budgeted is processed. Printed budget data and variance reports may also be obtained via the video display terminals. In addition, my staff also analyzes the variance reports, discusses significant items with the budget coordinators and/or the operating staff who developed the estimates and revises the budget where appropriate or necessary. The budget is then discussed with the managements of the various departments prior to review by the Chairman of the Board and the President.

The budget process is recognized throughout the Company as a critically important function. The expenditure of time and effort in preparing and reviewing it initially is significant; the review and analysis to which it is subjected is careful and extensive and requires the cooperation of all of the departments in the Company. Our experience has been that the budget process is effective; the revenues and expenses included in the 1984 budget are not significantly different from actual experience.

Q. Please explain the derivation of the inflation factors used for the 1985-86 budget.

A. Arriving at the inflation factors for budget purposes is not a pure mathematical computation, but rather encompasses reviews of several sources of forecast data and our best judgement as to the application of this data to the Company. In arriving at the inflation factors, the Company's Economist's Office uses information from Data Resources, Inc., the Fidelity Bank Econometric Model, the Conference Board, Mellon Bank, Citibank, Chemical Bank, First Pennsylvania Bank, E. F. Hutton, Paine Webber, Morgan Stanley, Morgan Guaranty Trust, and extensive financial forecast information prepared by Merrill Lynch and others.

Utilizing the information indicated above, inflation factors to be used in the budget preparation only in the absence of known cost changes were developed. These factors, 5.25% for 1985 and 6.4% for 1986 were developed in November 1984 in conjunction with our consultants, Putnam Hayes & Bartlett and National Economic Research Associates. These inflation rates are supported by Data Resources, Inc. Report: "U.S. Long Term Reivew: The Outlook to 1995", Summer 1984. The 1985 GNP deflator of 5% is approximately at the midpoint between the optimistic and pessimistic estimates of the G.N.P. deflator by D.R.I. in that document. The 6.0% GNP deflator for 1986 and beyond is close to the center of the D.R.I. rates in that document.

The inflation rates utilized for budget purposes are a composite of the GNP deflator estimates and wage rate estimates as indicated in the following table.

	1985	1986	1987 & beyond
GNP	5.0%	6.0%	6.0%
Wages	5.5%	6.8%	7.3%
PECO Rates	5.25%	6.4%	6.65%

The wage rate estimates are based on the assumptions that such increases are (a) related to the general inflation rate in the economy but with a lag of about one year, (b) higher than the general inflation rate when the inflation rate is low to moderate, and (c) equal to or lower than the general inflation rate when that inflation rate is high.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

PECo Statement No. 20

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION V.

PHILADELPHIA ELECTRIC COMPANY,

DOCKET NO. R-850152

DIRECT TESTIMONY

OF

RICHARD Wm. WRIGHT

EXPLANATION OF CERTAIN RATE BASE

AND EXPENSE ADJUSTMENTS

SEPTEMBER 27, 1985

DOCKETED
SEP 27 1985

Q. Please state your name and address for the record.
A. Richard Wm. Wright, 2301 Market Street, Philadelphia, PA 19101.
Q. By whom are you employed and in what capacity?
A. I am a Supervisor in the Financial Division of Philadelphia Electric Company.
Q. What is your educational background?
A. I graduated cum laude from the University of Virginia in 1972 with a BS in Mechanical Engineering. In 1975, I received a Master of Business Administration from Widener University.
Q. Please outline your experience with Philadelphia Electric Company.
A. Following my graduation from college in 1972, I joined Philadelphia Electric Company as a Test Engineer in the Electric Production Department. From 1972 to 1974, I was assigned to Cromby Generating Station and Peach Bottom Atomic Power Station. My responsibilities included conducting performance tests on turbines and boilers, assuring plant conformance with OSHA specifications, formulation of pollution incident prevention plans, and pre-operational testing of numerous nuclear plant systems.

From 1974 to 1976, I was assigned to the SAMAC project within the Services Division of the Electric Production Department. The SAMAC computer system monitors and controls all facets of the operation of Philadelphia Electric Company's electric generation and transmission systems. My responsibilities included supervision of all activities impacting the master data bank and remote data terminal transmissions as well as the development and implementation of a real time automatic economic generation control system.

In 1977, I transferred to the Finance and Accounting Department where I was assigned as an engineer in the Load and Cost Analysis Section of the Rate Division. My responsibilities included the development of load and cost analysis techniques necessary to meet PURPA requirements, development of a major time-of-day pricing research project, training all technical division personnel in computer programming, and participation in the preparation of testimony and interrogatories in Federal and Pennsylvania jurisdictional rate hearings.

In 1980, I transferred to the Budget and Control Division in the Finance and Accounting Department. My responsibilities in this position included the development and administration of corporate cost control programs, the design and production of the Company's quarterly report to shareholders, coordination of the departmental Quality Circle Program and membership in the Corporate Steam Heating Task Force.

In 1982, I was appointed to the position of Supervisor, Rates and Regulation Section of the Rate Division. I was responsible for the preparation of all filing requirements specified by regulations and the development and support, through testimony, of studies and exhibits as they relate to rate proceedings.

In May 1985, I was appointed to my present position as Supervisor, in the Financial Division in the Finance and Accounting Department. My present responsibilities include investor relations, preparation of the annual report, administration and performance measurement of the Company's pension plan, and the preparation of financing studies.

Q. What are your professional affiliations?

A. I have been a Registered Professional Engineer in Pennsylvania since 1976. I have been a member of the American Society of Mechanical Engineers since 1970.

Q. Would you outline your prior rate case experience.

A. I have participated in the preparation of rate cases and the preparation of exhibits for rate structure, as well as revenue, expense and other adjustments in prior filings including the 1979 Gas Rate Case (R-79030781), the 1979 Steam Rate Case (R-7904785), the 1979 Electric Rate Case (R-79060865), the 1980 Electric Rate Case (R-80061225), the 1982 Steam Rate Case (R-822101), the 1983 Electric Rate Case (R-822291), the 1983 Steam Rate Case (R-832434) and the 1984 Electric Rate Case (R-842590). I have prepared similar materials necessary for filing applications to the Federal Energy Regulatory Commission in support of rate increases to the Borough of Lansdale and Conowingo Power Company. Finally, I have testified in the 1983 Gas Rate Case (R-832410), the 1984 Electric Rate Case (R-842590), and at

Dockets ER84-9 and ER84-10 before the Federal Energy Regulatory Commission.

Q. What areas will your testimony cover in the present proceeding?

A. My testimony will cover the Company's rate base claim for four items which appear in the C Section of the Company's Accounting Exhibits TPH-1 and TPH-2: (1) non revenue producing construction work in progress, which appears on page C-8, (2) land held for future use, which appears on page C-9, (3) materials and supplies (exclusive of electric fuel inventory), which appears on page C-10, and (4) cash working capital, including average bank balances, which appears on page C-12.

My testimony will also support the following revenue and expense adjustments which appear in the D Section of the Company's Accounting Exhibits: (1) full year effect of present base rates, which appears on page D-2, (2) the adjustment to eliminate revenue and fuel expense associated with sales to the Borough of Lansdale, which appears on page D-13, (3) the decommissioning cost adjustment, which appears on page D-15, and (4) the spent fuel disposal cost adjustment, which appears on page D-16.

Q. Please explain the Company's claim for non-revenue producing construction work in progress.

A. Page C-8 of Company Exhibit TPH-2 provides the Company's claim for non-revenue producing construction work in progress and includes the location and description of each project, the associated construction authorization (C.A.) number, actual expenditures through June 30, 1985, the total estimated cost at completion, associated retirements, and the projected in-service date. These projects are safety or environmental related, meet the Commission's non-revenue producing and non-expense reducing construction work in progress standards, and are similar to projects whose inclusion in rate base as non-revenue producing and non-expense reducing construction work in progress has been repeatedly approved by the Commission.

The project at Eddystone (C.A. 205201) involves installing a coal pile runoff system consisting of two new retention basins equipped with plastic liners to prevent groundwater contaminination. This project is necessary in order to comply with Pennsylvania Department of Environmental Resources regulations regarding the prevention of groundwater contamination.

The reracking of the fuel pools at Peach Bottom (CA 408301) will increase the spent fuel storage capacity at Peach Bottom and will ensure the continued safe storage of nuclear fuel at this plant. This reracking will extend the capability to discharge a full core to storage for Units 2 and 3 from 1987/1988 to 1992/1993, respectively.

The upgrading of two containment isolation valves (CA 408526) on the backup safety grade nitrogen supply to the automatic depressurization system safety relief valves is necessary to provide complete containment isolation. The existing valves cannot provide a tight shut off in both directions.

Fire protection requirements of Nuclear Mutual Limited necessitate the installation of sprinkler systems at Salem Unit No. 2. These requirements include: a sprinkler system (C.A. 210182) in the welding shop and storage locker area of the turbine building, a sprinkler head over the waste compactor in the drumming and baling area, and a wet-pipe sprinkler system (C.A. 210908) in the oil storage room.

Development of the second stage of an ash and mine waste disposal site and associated waste drainage system (C.A. 202113) is required to provide waste disposal storage space at the Conemaugh Station in accordance with requirements of the Pennsylvania Department of Environmental Resources.

The installation of a water curtain spray system at Keystone Station (C.A. 406704) is necessary for safety reasons. The system will protect the turbine hall wall adjacent to the transformer bay in case of a fire.

Q. Mr. Wright, please explain the Company's claim for land held for future use.

A. Page C-9 of Company Exhibit TPH-2 contains the Company's claim for land held for future production, transmission, and distribution sites. Provided on page C-9 is the date these projects were originally included in Account 105, the expected date that construction is to start, the expected in-service date for each project, and the investment in each project at the end of the future test year.

The Commission has consistently approved rate base allowances for land held for future use where: (1) a definite plan exists for the use of the land, and (2) the utilization of the land will occur within a reasonable time period. In recent rate decisions, the Commission has determined that ten years is a reasonable time period. As set forth below, all of the projects listed on page C-9 are currently held under a definite plan for use in the Company's near term Electric Operations, and therefore satisfy the Commission's criteria for rate base treatment of this property.

Q. Please provide a description of each project on page C-9 and how each will be used.

A. The Bradshaw Reservoir Project consists of 38 acres of land required for the Reservoir and approximately eight miles of right-of-way for a water transmission line. The Bradshaw Reservoir is the final point of discharge for the water pumped from the Delaware River by and through the combined facilities consisting of the Point Pleasant intake, the pumping station, and the combined transmission main. At this reservoir the water will be divided and flow either by gravity to the North Branch of the Neshaminy Creek or under pump pressure to the East Branch of the Perkiomen Creek. The reservoir will provide sufficient water storage capacity to meet PECo's maximum flow requirement for one day. This emergency storage would be used in the event of the unavailability of the Point Pleasant facilities for this period of time. The reservoir has a water surface of about 18 acres. This project will be used in the operation of the Limerick Nuclear Generating Station.

The Merrill Creek Reservoir Project consists of 3,234 acres of land acquired to be used as a reservoir to provide cooling water to various Company generating stations. The Merrill Creek Project, which is a joint undertaking of seven utility companies, was required by the Delaware River Basin Commission as a condition for the withdrawal of water from the Delaware River for use in connection with the operation of the member companies' nuclear and fossil generating plants. This reservoir will provide a means of replacing water withdrawn from the Delaware River during certain periods of low river flow.

The Company's commitment to the Merrill Creek Project is a result of its Delaware River water needs associated with the operation of the Eddystone and Limerick generating stations. Moreover, future development of the Chester generating station site will also require replacement water from the Merrill Creek Project. In addition to Philadelphia Electric Company units, other units presently or soon to be operated by other member companies also contribute to the overall need for the Merrill Creek Project. The future uninterrupted generating capacity of all of these units requires the construction of the Merrill Creek project. Without Merrill Creek, it will be necessary to periodically curtail operations at one or more of these units in order to assure an adequate flow in the Delaware River at all times of the year.

The Limerick-Whitpain project land (133 acres) is associated with the construction of a 500 kv transmission line between the Limerick generating station and the Whitpain substation. This project is needed for Limerick Unit No. 2 and will also increase the reliability of the Company's transmission system.

Rate base allowances for each of the above three projects were approved by the Commission at Dockets R-811626, R-822291 and R-842590.

The Middletown substation land (9 acres) will be used for the construction of a 230-34 kv substation needed to service local distribution system growth. This project was approved by the Commission at Docket Nos. R-822291 and R-842590.

The Morton substation land (8 acres) will be used for the construction of a 230-138 kv stepdown substation. This substation will allow the Company to add a second supply source to Middletown substation. This second supply is needed in order to maintain system reliability at Middletown.

The Woodbourne substation land (22 acres) will be used for the construction of a 230-34 kv substation. The Dungan service building land (1/2 acre) is for construction of additions to the service building in order to maintain service to our customers. This project was approved by the

Commission at Docket No. R-842590.

As shown on page C-9, construction is currently under way on two projects, anticipated to begin on an additional four projects by 1988, with construction beginning on the remaining project by 1992. The anticipated in service dates for all of the projects are during the 1986 to 1992 period, which is well within the 10-year time frame previously established by the Commission in evaluating such claims.

Q. Please describe the Company's claim for materials and supplies exclusive of the fuel inventory component.

A. The Company's claim for materials and supplies exclusive of fuel inventory as detailed on page C-10 of Exhibits TPH-1 and TPH-2 consists of three components:

(1) The plant materials and supplies component, which represents the Company's investment in such items as boiler plant supplies, spare parts, pipefittings, pipe, wire and cable, and other miscellaneous supplies;

(2) The tools and related equipment component, which represents Electric Operations' portion of the Company's investment in tools and safety and protective equipment; and

(3) The stores expense undistributed component, which represents Electric Operations' portion of expenses incurred in the operation of the Company's storerooms.

The historic test year data for each of these categories reflect a 13-month average for the period June

30, 1984 through June 30, 1985. The future test year claim is based upon the estimate of investment in these items as of June 30, 1986.

The Company's materials and supplies balances are essential for safe, efficient and reliable operation. Maintenance of the reliability of the production, transmission, and distribution systems can only be accomplished with a sufficient inventory of materials and supplies on hand. Such an inventory is needed for emergency or rapid repair of plant to return it quickly to service in the event of a breakdown.

The Company carefully monitors materials and supplies balances to assure maximum operating efficiencies. A computer based inventory management system regulates materials and supplies balances so as to minimize requirements. Additionally, the Company has a centralized direct delivery system for transmission and distribution materials and supplies. This system reduces local storeroom inventory levels through increased reliance on central storeroom inventory levels and an enhanced interstoreroom delivery system.

Q. Why has the Company based its materials and supplies claim on investment projected at the end of the future test year?

A. Ratemaking is prospective, and the use of a future test year end investment level is critical if the rates set in this proceeding are to even partially reflect conditions which will exist during the initial period rates set in this proceeding are effective. The level of the Company's investment in materials and supplies is projected to increase during the future test year and beyond due to inflation and the addition of new plant and equipment to the Company's system. In addition, the use of end of test year balances is consistent with all other major components of the Company's claimed measure of value.

Q. Mr. Wright, why does the materials and supplies account increase from a June 30, 1985 balance of $41,314,000 to a $48,495,000 balance at June 30, 1986?

A. There are several factors contributing to this increase. The Company's claim is based upon an extensive survey of the Company's generating stations to determine their future materials and supplies needs for the budget period ended June 30, 1986. The bulk of the $7.2 million increase in the plant materials and supplies account reflects approximately $5.0 million for pumps, turbines, piping and other required materials and supplies required for the safe and reliable operation of Limerick 1. Eddystone Generating Station has budgeted an additional $300,000 for the test year, related in part to the scrubbers at the station. Peach Bottom Station will require an estimated additional $400,000 in order to institute safety system improvements. An adjustment of approximately $1,200,000 was made to reflect the impact of anticipated inflation on material and supply costs.

Q. Mr. Wright, please describe the Company's claim for cash working capital.

A. Page C-12 of Exhibits TPH-1 and TPH-2 details the Company's cash working capital requirements for the historic and future test years. The Company's claim for cash working capital at June 30, 1986 totals $99.4 million, and consists of three components: operating and maintenance expenses, taxes, and average compensating bank balances.

The Company's methodology for determining cash working capital is the same as that approved by the Commission at R-842590. In previous Company rate proceedings, the Commission adjusted the Company's cash working capital claim to reflect a theoretical availability of revenue prior to the payment of interest on long-term debt. In the Company's view, long-term debt interest is a part of the Company's return and is therefore the property of investors from the moment of receipt. If this interest is used to finance part of the Company's working capital requirement, that use is a reinvestment of funds by our investors and the investors are entitled to a return for that use. In addition, it is the Company's position, as set forth in prior proceedings, that there is no lag in the payment of bond interest. On the contrary, revenues lag interest payments, thereby creating an additional working capital requirement. However, for purposes of this proceeding the Company has included a $36.5 million debt interest and preferred dividend offset to its cash working capital claim in an effort to avoid controversy and to simplify Commission investigation of this case. This offset is presented on pages C-12c and C-12d of Exhibits TPH-1 and TPH-2.

Q. Mr. Wright, please discuss the Company's methodology for determination of its cash working capital requirement.

A. As in past cases, the Company first performed a lead/lag computation analyzing the payment patterns of residential, commercial, and industrial customers to determine the average lag in receipt of revenue. This specific methodology was ordered by the Commission at Docket R-811719 and has been previously accepted by the Commission at Docket R-842590. The lag in receipt of revenue, as based upon this Commission accepted approach, for the period studied was 46 days. A summary of the Company's revenue lag study is attached to this Testimony as Appendix A.

Q. Mr. Wright, what does Appendix A indicate?

A. As indicated in Appendix A, the Company has analyzed residential and commercial electric revenues for six of the 21 billing routes for the twelve month period ending with February 1985 meter readings. For each of the billing routes for a particular month, actual cash receipts (payments) were accumulated on a day-by-day basis starting from the meter reading date and continuing approximately four months beyond the meter reading date. Therefore, the meter readings for the twelve months ended February 1985 include the actual cash payments for the four-month period beyond the meter reading date, ending with June, 1985.

In the case of industrial customers, the computation was based on six billing routes for the months of February and March of 1985. The industrial accounting system was being computerized from October 1984 through January 1985 and, hence, data from this transition period is not available.

The revenue weighted average was taken for residential, commercial, and industrial customers and to that average 15 days were added to account for the midpoint of the period of monthly service rendered to each group. This resulted in 49 lag days for residential customers, 48 days for commercial customers, and 44 lag days for industrial customers. The resultant lag days were then weighted by actual revenue for each of the rate schedules listed on page A-5 of Exhibits TPH-1 and TPH-2.

At the end of the four month period, service to customers with outstanding revenue is terminated and the outstanding revenue is submitted for final collection. In the course of this collection process, a series of steps are taken in a final effort to secure payment prior to writing off the revenue. This final collection procedure is initiated at the time the service is terminated and takes another 74 days after which time revenue is written off and declared uncollectible.

In the Company's last electric rate proceeding at Docket R-842590, the Commission ruled that uncollectible account expense should be removed from operating and maintenance expenses for purposes of calculating a cash working capital requirement. Accordingly, uncollectible accounts expense is removed from the cash working capital claim on page C-12a at footnote (e).

For purposes of this proceeding, the impact of the 74 day uncollectible accounts expense collection period has been incorporated in the calculation of revenue lag. It is necessary to include this adjustment in order to properly reflect a known lag in the receipt of revenue occurring beyond the four month period in which revenues are explicitly tracked.

Total class revenues for the month were then weighted by the average lag in the receipt of revenues for each of the six routes to determine a time weighted revenue figure. This figure, along with the total class revenues, was accumulated over the twelve month period ending with February 1985 meter readings to develop a twelve month revenue weighted average lag in the receipt of revenue.

Q. Mr. Wright, what procedure was followed in the analysis of average lag in the payment of expenses?

The Company has performed detailed studies for the average lag days in payment of expense for each category listed on Page C-12a of Exhibits TPH-1 and TPH-2. The average lag in the payment of operating expenses utilizing proforma expense levels indicates a lag of 20 days for the historic test year and 22 days for the future test year. The average lag between the receipt of revenues and the payment of operating expenses is applied to the average daily proforma test year O&M expense level to derive the working capital requirement.

As part of this expense lag calculation, the Company has performed a detailed analysis in order to determine the average lag days associated with the payment of other invoices. A sample of approximately 3,800 invoices was analyzed. The lag days for each invoice were computed and then weighted against the invoice amount. Based on this analysis, the average lag day for other invoices was determined to be 15 days. A summary of the lag day analysis for all expense categories is provided in response to filing requirement II-B-4.

Q. Mr. Wright, how is the cash working capital requirement for the payment of taxes developed?

A. First, the average lag in the payment of taxes is developed on the basis of proforma taxes as shown on page C-12b of Exhibit TPH-2. This analysis indicated a lag of 22 days for the historic test year and 28 days for future test year. This payment lag is then subtracted from the average lag in the receipt of revenues to develop an average lag between the receipt of revenue and the payment of taxes. The resultant average lag is applied to average daily proforma test year taxes to derive the cash working capital requirement.

Q. Mr. Wright, please describe the Company's claim for a $9.7 million cash working capital requirement to support

Electric Operations' portion of average monthly bank balances.

A. These bank balances are maintained to support the Company's lines of credit and to compensate the banks for the cost of numerous services provided to the Company as well as to meet normal operating cash needs.

Bank credit is the most convenient and flexible source of short-term funds available to the Company, and the furnishing of such credit is the most valuable service performed by the Company's depository banks. Such credit is available on demand, and funds can be taken down and repaid at the discretion of the Company. Providing such a continuous service has its costs, and banks have traditionally required customers to have enough funds on deposit to compensate them for these costs. At June 30, 1985, the Company had $351.7 million of bank credit lines of which $178.2 million were supported by compensating bank balances.

In addition to supporting the cost to the bank of making this credit continuously available, compensating balances have enabled the Company to borrow at an interest rate lower than otherwise possible. For example, in situations in which the Company has obtained bank credit under a fee arrangement, the interest rate paid on borrowings was primarily at the bank's prime rate while the Company was able to negotiate rates below prime at most of its line banks where compensating balances were maintained.

A third reason for maintaining bank balances is to compensate banks for the cost of numerous non-credit services provided the Company. These services include traditional third-party payment services (i.e., checking accounts and utility payments), money mobilization services (i.e., wire transfers and courier services), special check sorting and listing services, including advice and information on money market investments or services as agents in the sale of commercial paper.

Bank balances are also kept to meet normal operating needs for cash. Payroll requirements, tax payments, interest and dividend payments, fuel payments and other peak demands for disbursements necessitate the maintenance of minimum cash reserves since such disbursements do not always parallel revenue collections from customers.

I should note that the Company is able to maintain average daily balances at the minimum possible level due to its sophisticated cash management program which was described as both effective and innovative in the management audit report ordered by the Commission. The utilization of such technological innovations as bank direct send techniques, direct deposit of receipt items through a check sorter, rapid extraction desks (envelope openers), and an in-house, high-speed check encoding facility increases the availability of the funds collected, thereby reducing receipt float.

In addition, our cash management program takes full advantage of the disbursement float and zero balance accounts for paying the Company's bills. Varying proportions of our daily disbursement take from one to four days to pass through the check clearing system. On our records, we deduct these disbursements at the time a check is issued. However, the bank's records do not reflect this charge until some later time when the check is presented for payment. Taking advantage of disbursement float reduces our minimum bank balance requirements.

Also, several of our line banks provide us with a tape of customer payment information which allows us to update our customers' records immediately upon receipt. These banks and their branches are available to our customers for bill payments. The availability of this service is a major convenience to our customers. PECO also maintains accounts at many smaller banks for the sole purpose of allowing our customers the convenience of paying bills locally. The cost of providing this service is partially offset by the minimum cash balances kept in these small accounts.

Q. Have you any documentary support for the understanding that such balances will be maintained?

A. Yes, I do. Letters from our major depository banks stating their understanding that such balances will be maintained are set forth in response to filing interrogatory II-B-5 which indicates current credit lines. The terms of this understanding as reflected in these letters is that balances will be maintained to compensate the bank for the major services described - i.e., the availability of credit, borrowings under such credit and normal bank services.

Q. Mr. Wright, please discuss the Section D schedules sponsored by you in sequence including any explanations you consider necessary.

A. Page D-2 reflects the full year revenue effect of Tariff No. 26, Supplement No. 11 which became effective January 25, 1985. Since the historic test year represents the twelve month period ending June 30, 1985, it does not reflect the full year effect of the Company's $149.6 million base rate increase granted by the Pennsylvania Public Utility Commission on January 24, 1985. Therefore, it was necessary to increase the historic test year electric base revenues by an additional $87.3 million to show the revenues which the Company would have collected if Tariff No. 26 had been in effect during the entire twelve month period, July 1, 1984 through June 30, 1985.

An adjustment for the twelve months ended June 30, 1986 was not required since the Company's budget year was developed including the Tariff No. 26, Supplement No. 11 rate levels.

Page D-13 eliminates the revenue and the fuel expense associated with sales to the Borough of Lansdale and to Jersey Central Power & Light. Effective July 7, 1985, the Borough of Lansdale no longer receives its power supply from the Philadelphia Electric Company. Effective December

31, 1984, Jersey Central Power & Light no longer purchases the output of Salem #2 from PECo. This adjustment is necessary to the historic test year to establish a normalized level of revenue and expenses that will exist when rates are established by the Commission in this proceeding.

Q. Please describe the Company's claim to recover nuclear plant decommissioning costs.

A. <u>Page D-15</u> of Exhibits TPH-1 and TPH-2 represents the Company's claim to recover its share of the cost of decommissioning Peach Bottom, Salem, and Limerick 1. The claim is in two parts: (1) a $10.021 million annual expense accrual and (2) a $2.870 million annual accrual reflecting a five year amortization of an adjustment necessary to bring the decommissioning fund in line with the current estimated total cost of decommissioning. The resulting total annual decommissioning expense claim is $12.891 million.

Q. Why is it appropriate for the Company to recover decommissioning costs in this proceeding?

A. Decommissioning is a known cost that the Company will incur when nuclear units are retired. Decommissioning expenses are an integral part of the costs of providing low cost nuclear generation. The Company's claim equitably recovers the cost of decommissioning over the life of the nuclear units.

The Company's decommissioning expense claim in this proceeding is based upon a detailed site specific study prepared by NUS Corporation. This study identifies a total decommissioning cost to the Company for the nuclear portion of Peach Bottom, Salem and Limerick #1 to be $272,908,000 in March 1984 dollars. The results of the decommissioning cost study are described in detail in the Direct Testimony of N. Barrie McLeod, PhD.

The decommissioning cost identified in the study was escalated from its March 1984 basis to a June 1986 basis to coincide with the data presented in the filing. As described in the Direct Testimony of Dr. McLeod, the total decommissioning cost is segregated into eight categories for purposes of this escalation. These cost categories are escalated to known levels at March 1985, and then are escalated from March 1985 to June 1986 using individual estimates of inflation and other specific cost increases on each of the eight cost categories. Appendix B itemizes the cost categories and escalation factors utilized in the Company's decommissioning claim.

The total cost of decommissioning at June 30, 1986 is then amortized in order to determine the annual accrual portion. The amortization period differs for each plant since it is based on the time when the Company starts collecting for decommissioning expenses until the time the decommissioning process begins.

In addition, the Company is making a $2,870,000 claim to adjust the existing decommissioning reserve with the current estimate of total decommissioning cost. Because of the large size of the adjustment necessary in this proceeding, the Company has recommended a five year amortization to mitigate the impact of this item on customers. Prior accrual correction is a procedure recognized and approved by the Commission at Dockets R-811626, R-822291 and R-842590.

Q. Mr. Wright, please discuss the Company's claim for the recovery of nuclear spent fuel disposal costs shown on Page D-16 of Exhibits TPH-1 and TPH-2.

A. When nuclear fuel has been discharged from the reactor it must be disposed of safely and permanently. The cost of this disposal is a clearly definable cost element which should be borne by those using and benefitting from the energy generated while the fuel is in the reactor.

Q. Why is the Company making a claim for the recovery of costs of spent nuclear fuel.

A. The "Nuclear Waste Policy Act of 1982", which became effective on January 7, 1983 when it was signed by President Reagan, ordered the Department of Energy to promptly enter into spent fuel disposal contracts with utilities to pay for the ultimate disposal of spent fuel.

In compliance with Section 302 of the Act, on April 7, 1983 the Department of Energy began assessing 1 mill for each kWh of gross electrical output of a nuclear power plant to pay for the shipment and ultimate permanent disposal of spent fuel discharged on or after that date.

The direct implementation of the terms of this Act is through a spent fuel disposal contract between DOE and each utility with an operating nuclear power plant.

Contracts for the disposal of fuel for Peach Bottom Units 2 and 3 and Limerick Unit 1 were signed by the Philadelphia Electric Company on June 1, 1983. The Company's ownership portions in these plants are 42.49% and 100% respectively. A similar contract has been signed by Public Service Electric and Gas Company, the operating partner for Philadelphia Electric Company's 42.59% owned portion of Salem Units No. 1 and No. 2. The 1 mill/kWh fee will be evaluated annually by DOE on the basis of actual and projected program costs and direct transport and disposal costs. The fee is therefore subject to future adjustment, but such adjustments will not be retroactive.

Q. Please describe the basis for the Company's current claim for spent fuel disposal cost as shown on page D-16 of the Company's Accounting Exhibits.

A. The Company's claim is developed by applying the 1 mill per kWh charge to the ownership portion of the normalized annual gross generation for Peach Bottom Units No. 2 and No. 3, Salem Units No. 1 and No. 2, and Limerick Unit No. 1. The result is an annual expense of $17,075,000. The normalized annual gross generation estimates are provided by Company witness John J. Carroll.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

Philadelphia Electric Company - Electric Operations
Revenue Lag Study Summary

Residential

Lag Days	Routes 2	9	10	12	14	17	Weighted Average
Mar. 1984	30.6	35.8	33.7	35.0	33.9	34.3	33.8
Apr.	*	*	*	*	33.9	33.6	33.7
May	*	*	*	*	31.2	33.8	32.4
Jun.	*	*	*	*	31.4	31.0	31.2
Jul.	30.7	*	*	*	30.1	32.6	31.1
Aug.	31.2	34.7	32.7	34.5	33.1	33.6	33.2
Sep.	32.5	34.4	32.5	32.3	32.3	31.7	32.6
Oct.	32.1	35.1	32.0	34.6	33.1	33.2	33.3
Nov.	31.5	36.5	33.4	35.1	34.4	32.1	33.8
Dec.	29.9	35.1	*	33.1	34.2	34.1	33.1
Jan. 1985	31.0	32.4	31.1	32.7	32.6	33.2	32.1
Feb.	31.0	34.4	32.4	33.5	*	33.4	32.8

Revenue Weighted Average 32.7 days

Revenue Weighted Average	32.7
Midpoint of Usage - Monthly	15.0
Uncollectible Accounts	0.9
	48.6

*Not Available

Philadelphia Electric Company - Electric Operations
Revenue Lag Study Summary

Commercial

Lag Days	Routes 2	9	10	12	14	17	Weighted Average
Mar. 1984	31.8	33.4	32.6	32.5	34.3	32.8	32.9
Apr.	*	*	*	*	33.2	32.4	32.8
May	*	*	*	*	32.4	33.5	32.9
Jun.	*	*	*	*	31.6	30.1	32.9
Jul.	34.1	*	*	*	30.3	31.8	30.9
Aug.	35.3	33.2	32.1	33.2	33.5	32.6	32.1
Sep.	34.5	32.3	30.6	30.8	32.1	29.9	33.4
Oct.	34.1	34.0	30.3	34.3	33.2	32.7	31.8
Nov.	33.0	34.6	33.5	34.3	34.3	29.7	33.1
Dec.	31.2	33.9	*	32.6	33.9	31.8	33.1
Jan. 1985	32.9	30.1	32.5	32.7	33.4	33.9	32.7
Feb.	32.4	34.0	34.2	33.3	*	32.9	32.6
							33.4

Revenue Weighted Average 32.6 days

Revenue Weighted Average	32.6
Midpoint of Usage - Monthly	15.0
Uncollectible Accounts	0.6
	48.2

*Not Available

Philadelphia Electric Company - Electric Operations
Revenue Lag Study Summary

Industrial

Lag Days	3	6	15	16	18	21	Weighted Average
Feb. '85	29.0	30.4	37.3	27.3	29.1	25.6	27.9
Mar. '85	29.4	27.6	43.9	27.4	29.9	27.6	29.1

Revenue Weighted Average 28.49

Revenue Weighted Average	28.5
Midpoint of Usage - Monthly	15.0
Uncollectible Accounts	0.6
	44.1

Decommissioning Cost Categories, Indices
and Escalation Factors

Cost Category	Mar.'84 Index (1)	Mar.'85 Index (2)	June' 86 Index (3)	Mar.'84 - June'86 Escalation Factors (4)=(3)/(1)
Craft Labor, Skilled	353.6	374.3	405.0	14.5%
Craft Labor, Common	420.0	457.3	502.0	19.5
Professional/Technical Labor	122.2	127.7	135.0	10.5
Equipment	355.8	361.8	372.0	4.6
Low Level Waste Burial	21.57	25.49	25.49	18.2
Iron & Steel Scrap	311.8	286.2	275.0	(11.8)
Copper Scrap	149.6	128.8	135.0	(9.8)
Energy and Other	309.6	313.1	326.0	5.3

Note: March 1984 and March 1985 indices represent actual data from the sources listed on page 4-29 of Exhibit NBM-1. June 1986 indices represent Company estimates of these categories as explained in the Direct Testimony of R. W. Wright.