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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

Supplemental
Direct Testimony

of

Joseph F. Brennan, President
Associated Utility Services, Inc.

Concerning

The Energy Cost Rate

Q. ARE YOU THE SAME JOSEPH F. BRENNAN WHO OFFERED RATE OF RETURN TESTIMONY IN THIS PROCEEDING?

A. Yes. My testimony on rate of return issues was previously admitted in evidence as PECO Statement 28. A full statement of my qualifications is provided in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. I have been requested by Philadelphia Electric Company (PECO) to assess the likely effect upon the Company's financial position and standing in the investment community of modifying the energy cost rate (ECR) to allow reconciliation for over/under collection of only 80% of PECO's total energy costs. In preparing my testimony, I have performed a general review of the background of incentive fuel cost adjustments, and I have assessed the likely financial impact of the proposal made specifically for PECO on the financial integrity of the Company.

Q. HAVE YOU PREPARED AN EXHIBIT TO ACCOMPANY THIS SUPPLEMENTAL TESTIMONY?

A. Yes. Exhibit JFB-2, comprised of 6 Schedules.

Q. DOES THE PRESENCE OR ABSENCE OF A MECHANISM TO ALLOW FULL AND TIMELY RECOVERY OF FUEL COSTS HAVE AN EFFECT ON THE PERCEPTION OF AN ELECTRIC UTILITY'S RISK?

A. Yes. Automatic fuel cost adjustment mechanisms such as the ECR are a key factor in stabilizing the variation in an electric utility's earnings and rate of return, and hence, investor perception of risk. Variations in earnings and rate of return can make the difference between rating grades with respect to long-term debt, keeping in mind the fact that earnings on equity provide the margin by which fixed charges are earned more than once, and the difference between stocks selling at or below book value. To the extent that fuel costs are not recovered in a timely manner, swings in earnings wider than otherwise may occur to the point of an investor perception of increased business risk. Moreover, to the extent that rising fuel costs are not fully recovered, there may be a deterioration in a utility's earned rate of return, which can cause downgradings of long-term debt, falling stock prices, and resultant higher cost of capital ultimately reflected in the price of service to the detriment of all, including consumers. Such factors are precisely the situation that led to the institution of energy adjustment clauses in the 1960's. The combination of general inflation and rapid inflation in fuel costs beyond the control of utilities had impaired seriously the financial integrity of many utilities. In periods of increasing fuel costs, utilities' cash flows were strained as the gap between incurred and recovered costs widened. The ECR was designed not to provide additional revenues to the Company but to provide stability in cash flow and earnings so as to mitigate against the increasing riskiness of utilities because of rising and fluctuating fuel costs.

In essence, there has been an implicit compact between utility investors, customers, and regulators. Investors receive no loss or benefit from changes in fuel costs. In turn, they receive prompt payment for expenses incurred for any fuel or purchased power costs. Customers benefit by a lower price of service than otherwise in the form of a lower cost of capital. This lower cost of capital is obtained from a more predictable and dependable level of income and reflected in the price of service.

Q. MR. BRENNAN, IS THERE ANY DIRECT EVIDENCE THAT RATINGS AGENCIES, AND THE INVESTMENT COMMUNITY GENERALLY, CONSIDER THE PRESENCE OF AN ADEQUATE AND FAIR FUEL ADJUSTMENT CLAUSE AN IMPORTANT FACTOR INFLUENCING RISK AND RATINGS?

A. Yes. The two major rating agencies, Moody's Investors Service (Moody's) and Standard & Poor's Corporation (S&P) monitor regulatory practices and whether credit quality is adequately protected by allowing for timely recovery of fuel and other costs.

For example, a November 11, 1978, Moody's article captures the essence of these credit concerns:

> Today, utilities face a number of uncertainties. Costs are going up, construction programs are increasingly subject to regulatory and environmental delays, load forecasting is more difficult and fuel cost as well as its supply is problematic. And these are but a few factors in the package of challenges facing the industry. There are many cost factors which are basically beyond the control of the utility, assuming it is to serve its customers adequately. Moderation of the risk borne by the investor as these cost increases squeeze profits is strictly in the hands of the regulators.
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> As cost and risk rise, regulators must respond with higher rate approvals. If effective action is not taken, for example, to curb our nation's dependence on imported energy while concurrently producing over-all inflation, why must the utility bear the burden? If there is an increase in primary energy cost, why must the utility stand by and only hope to recover it in time? Certainly, it should expect and, indeed, deserves, an automatic adjustment for this and other significant and unavoidable expenses.
>
> Without a neutralization of risk factors through prompt and reasonable rate treatment, today's utility will be hard pressed to maintain its financial posture without a significant reduction in debt levels. While we are certainly in favor of some reduction in debt levels we also recognize that, in general, significant reductions would limit expansion capability. The only feasible solution is regulation which is sensitive to the bondholder's need as

reflected in improving earnings protection and cash flow. Some state commissions are probing successfully in their efforts to strike the correct regulatory balance while some others do not seem to be aware of the problem. Ratings must reflect the differences.

With respect to S&P, an example of their concern is their June 1982 response to a Michigan legislative initiative which would have, among other things, abolished all rate adjustment mechanisms. S&P responded by placing most utilities in Michigan on their watch list for potential rating changes. In its discussion of the Michigan legislative initiative, S&P stated:

> The initiative's negative impact on credit quality would likely range from moderate for telephone companies to major for the gas and electric utilities. At a minimum, the risks of under recovery of increases in operating costs would appear to be substantial. Primarily affected are purchased gas, the largest expense item for gas distributors, and fuel costs for electric generation, the highest expense for electric utilities. Automatic gas fuel, and purchased power adjustment clauses have long been in effect in virtually all states and are very significant in the process of matching revenues with expenses. These rapid energy cost recovery mechanisms are regarded as critical elements of earnings stability for gas and electric utilities.

Q. CAN YOU CITE ANY OTHER INSTANCE OF RATING AGENCY CONCERN WITH RESPECT TO A FUEL ADJUSTMENT CLAUSE?

A. Yes. In 1980, the Missouri Supreme Court ruled that fuel adjustment clauses were unlawful. As a result, the Missouri Public Service Commission eliminated the fuel adjustment clause, and this partly contributed to S&P's downgrading of Missouri Power & Light's debt rating to "BBB" from "A-." In its rationale, which was published on August 2, 1980, S&P stated: "While capital pressures can generally be regarded as manageable, regulatory actions have not provided for the adequate recovery of operating costs. Taking into account recent rate decisions by the Missouri Public Service Commission, substantial improvements in regulatory treatment will be necessary, in particular, with the elimination of the fuel adjustment clause, the need to pass-through purchase power expenses on a current basis has been heightened."

Q. WILL A CHANGE IN PECO'S EXISTING ECR BE VIEWED AS ADDING RISK TO PECO?

A. Yes, without caution and due regard for the fact that PECO's financial position at this time is quite less than robust, it is clear that a change in PECO's existing ECR will increase PECO's business risk.

Q. WHY IS PECO'S CURRENT FINANCIAL POSITION AN IMPORTANT FACTOR?

A. Prior to the advent of ECR type treatment, many electric utilities, including PECO, were quite financially healthy as evidenced by bonds of high investment grade, such as AA and AAA, and a common stock market price consistently above book value. Subsequent to the rapid and significant rise in fuel costs, bond ratings were reduced several grades to barely investment grade and a price of stock less than book value. If electric utilities had not possessed a healthy financial position at the outset, the ability to withstand the severe financial pressure of a rise in fuel costs could have led to bond ratings less than investment grade, stock prices lower than otherwise, and a cost of capital reflected in the price of service higher than otherwise. When the financial condition of the electric utility is already at the very bottom of the investment grades, a change in the ECR should be made only with the utmost care and caution.

Q. WHY IS PECO A RELATIVELY HIGH RISK ELECTRIC COMPANY?

A. In part, it is the environment in which PECO must operate. PECO is located in an area of changing economic activity. The risk that PECO is exposed to is derived from that environment. The business risk of the utility business in the Philadelphia area arises not only from the business risk of utilities generically, but also from the risk associated with the service territory. The service territory is characterized by a change-over from an industrial economic base to a service economic base. Industrial activity has been declining. One need only drive around the formerly thriving industrial areas of Philadelphia to observe the changes. Philadelphia and other areas in the Northeast find it difficult to compete for the electricity and labor intensive industries which were formerly the area's industrial base. While the electric industry in general is more risky than previously, utilities serving the major cities of the Northeast are faced with problems greater than those faced by those in the industry in general.

Q. WHAT ARE THE INDICATIONS OF PECO'S HIGH-RISK CHARACTERISTICS?

A. I discussed those in my testimony regarding fair rate of return. The most prominent is the Company's bond rating, which is Baa3 by Moody's and BBB- by Standard & Poor's. These are the lowest of investment grade bond ratings. Should bond ratings drop any further, major institutional investors under the standards of prudence will not be able to purchase PECO bonds. Electric utilities whose rating is less than investment grade have been able to sell "Junk Bonds," but "Junk Bonds" have a very limited market and related very high cost. Quite obviously, a higher cost of capital ultimately would need to be reflected in the price of service charged to consumers. It is therefore most important that great care should be taken to not increase risk by a too severe modification in the ECR.

Q. PLEASE BRIEFLY DESCRIBE YOUR UNDERSTANDING OF THE PROPOSED CHANGES IN ECR.

A. My understanding of the proposal is derived from a review of the Commission's October 30, 1985, Order in its investigation of PECO's ECR No. 8 filing at Docket No. M-840375, et al. The proposal directs PECO to file an amended ECR rider in which only 80% of experienced over/under collections are recovered through the ECR. The remaining 20% over/under collection would not be subject to after the fact reconciliation. It has been suggested that these measures will provide an incentive to utility management to minimize fuel costs.

Q. IS IT NECESSARY TO PROVIDE ADDITIONAL INCENTIVES TO PECO'S MANAGEMENT TO STRIVE TO MINIMIZE ENERGY COSTS?

A. In my opinion, adequate incentives are already in place. This Commission has instituted a fuel audit procedure through which procurement decisions are reviewed in detail. Imprudence in fuel management practices can be detected in this process, and appropriate action can be taken. Secondly, PECO is a member of the PJM Power Pool which automatically dispatches electricity from the lowest cost source. Thirdly, prudent utility managers are cognizant of the impact of rate levels. The ECR mechanism brings nothing to net income. Higher fuel costs do not benefit the investor. They do, however, have negative economic and public relations value. Customers react to higher prices, both in terms of their attitude toward the Company and their use of electricity. All other things being equal, customers will strive to use less energy with higher rates.

Q. ARE THERE ANY FLAWS IN AN INCENTIVE FUEL CLAUSE CONCEPT?

A. There are two obvious flaws. Without proper safeguards, there could be an investor-perceived increase in risk resulting from the implementation of an incentive fuel clause. Investors could require capital costs rates that are higher than would otherwise be the case. If investors observe regulatory caution and a legitimate possibility of higher than otherwise earnings due to the possibility of an ECR modification, there likely would be risk sharing and potentially shared benefits.

There is an inherent difficulty in accurately forecasting fuel costs. PECO has been criticized for failing to accurately forecast future energy costs, but actual fuel costs are the result of many unanticipated circumstances beyond PECO's control. Among them are forced outages, generating plant safety inspections, greater than forecasted loads which require the use of less efficient generating units, and swings in the market price of fuel. Even the most prudent management cannot anticipate or offset the effects of these unforeseeable events.

The Company has developed two sensitivity scenarios to show the impact of uncontrollable variations on fuel costs. The two scenarios and the estimated annual change in fuel and purchased power expenses as developed by PECO Witness John Carrol are:

Scenario	Annual Increase in Fuel and Interchange Expenses with an 80% ECR		
	Twelve Months Ended June 30,		
	1987	1988	1989
	(Millions of Dollars)		
Coal Scenario	108.9	137.4	136.8
Nuclear Scenario	129.4	141.3	232.2

The two sensitivity scenarios studied by PECO Witness John Carrol include a coal and a nuclear scenario. The three time periods studied for each of the scenarios include estimated mid-1986-1987, estimated mid-1987-1988, and estimated mid-1988-1989.

Q. WHAT IS THE IMPACT ON INCOME AVAILABLE TO COMMON EQUITY BEFORE AND AFTER-INCOME TAXES RELATED TO AN 80% ECR REGARDING THE TWO SCENARIOS FOR THE THREE FUTURE PERIODS ON AN ESTIMATED BASIS?

A. With an 80% ECR, an approximation of the impact on net income before-income taxes ranges between $21.8 million and $46.4 million. On an after income tax basis, the estimated impact ranges between $10.9 million to $23.2 million. This information is shown on page 1 of Schedule 1.

Q. IS THERE OTHER INFORMATION SHOWN ON PAGE 1 OF SCHEDULE 1?

A. Yes. I have shown the impact of each scenario on the rate of return on common equity assuming an 80% ECR. With an 80% ECR, PECO stockholders could experience a downward movement in the rate of return on common equity after income tax ranging from 0.32% to 0.62%, or a mid-point of 0.47%. On a before income tax basis, the impact would be approximately double, given an assumed 50% income tax rate, or 0.64% to 1.24%, or a mid-point of 0.94%.

Q. HAVE YOU DEVELOPED A TABULATION TO INDICATE THE LEVEL OF FORECASTED BEFORE-INCOME TAX INTEREST COVERAGE AND ESTIMATED DETERIORATION IN THE LEVEL OF BEFORE-INCOME TAX INTEREST COVERAGE IF THE ACHIEVED RETURN RATE ON BOOK COMMON EQUITY WAS TO BE 0.62% ON AN AFTER-INCOME TAX BASIS LOWER THAN OTHERWISE?

A. Yes. That information is shown on Schedule 2. Since the opinion of bond rating agencies affects the decision of investors, as evidenced by the fact that the cost rate for long-term debt is measurably higher as lower ratings are assigned, and vice-versa, I have shown the impact inclusive and exclusive of AFC (allowance for funds). Under the new, more stringent, Standard & Poor's (S&P) coverage yardsticks published February 18, 1985, (and attached as pages 4 and 5 of Schedule 2) interest coverage for S&P bond rating purposes is calculated without regard to AFC. Further, in regard to PECO, the amount of AFC will change as a result of the rate base recognition of Limerick I and 100% of common plant.

Q. WHAT IS THE RESULT OF YOUR CALCULATIONS?

A. As can be seen by referring to page 1 of Schedule 2, the calculation with all AFC included suggests coverage of interest of long-term debt of about 3.6 times. When AFC is excluded from the calculation, the coverage falls to approximately 1.6 times. If it is assumed all Limerick I and common plant related AFC is replaced with cash earnings, the before-income tax coverage would be 3.1 times. It should be stated that to the extent something less than the rate base or expense claims of the Company relative to Limerick I and common plant was reflected in the price of service, the level of coverage excluding AFC after Limerick is in the rate base would be something less than 3.1 times.

On page 2 of Schedule 2, I have shown identical calculations except I have also reflected the impact of the maximum calculated decline in the rate of return on common equity related to the sensitivity calculations of Company Witness John Carrol and the two scenarios and time periods previously mentioned. The calculations reflect the largest decline, or 0.62% on common equity on an after-income tax basis and 1.24% on a before-income tax basis. Please note that excluding all AFC, the basis employed by S&P with respect to developing coverage for bond rating purposes, the level of before-income tax interest coverage would be 1.5 times, which is but 0.1 times lower than produced by the calculation without regard to the sensitivity. While the impact is small, the more important point is the level of coverage before or after the impact of the sensitivity analysis. Either 1.6 or 1.5 before-income tax interest coverage is dangerously close to a level insufficient to command an investment grade bond rating. Please further note that on page 5 of Schedule 2, I have reproduced an excerpt from S&P's Credit Comment dated February 18, 1985, wherein they announce revised new (more stringent) benchmarks for electric utilities with respect to obtaining a particular bond rating. Please observe the fact that for bonds rated BBB, the very bottom of investment grades, the minimum level of coverage is 1.5 times.

Please also note on page 2 of Schedule 2 that excluding AFC related to Limerick and common plant, in other words based on the assumption that there was cash earnings replacing Limerick I and common plant related AFC, the level of coverage would be 3.0 times after the impact of common stockholder absorption of a 0.62% impact of an 80% ECR and the most adverse of Witness John Carrol's two scenarios. Again, it should be stated that this calculation proceeds from the premise that all of the Company's rate base claim in the Limerick I rate case, again, for clarification, including all common plant, is reflected in rate base for rate making purposes and to the extent anything less is reflected in the rate base or expenses for rate making purposes, the level of coverage would be below the 3.0 times level.

For further clarification, it should be stated that these calculations proceed from an approximation of the capital structure and cost rates for long-term debt and preferred stock and a starting point estimated income level for common equity based upon the Company's budgetary June 30, 1986 income statement is evidence in this proceeding (Schedule B-8 of Exhibit TPH-2). For simplicity, I have assumed a 50% income tax rate for the purpose of these calculations.

The end result of these calculations clearly demonstrates that PECO's financial position at this time is very sub-standard. Further, any significant added risk prior to the achievement of the income level related to new service rates inclusive of Limerick I could result in PECO's bonds being rated less than investment grade. It is for this reason I urge the Commission to cautiously experiment with respect to a modification of the ECR in the best interest of consumers as well as investors. I believe this data, together with other factors I will discuss, clearly demonstrates a need for a cap on the 80% experimental ECR, at least at the outset and possibly for a few years. A cap will serve to put on notice both investors and rating agencies that there is a regulatory intention to preclude a financial result insufficient to maintain as a bare minimum the bottom of investment grade ratings. Without the cap at the outset and an investor perception of such regulatory intentions, I believe the potential benefit of a modified ECR as proposed by the Commission may prove to be counter productive and obviously not in the public interest.

It should also be noted that there looms on the horizon other new risk factors facing investors in PECO's long-term debt and common stock. For instance, the Financial Accounting Standards Board (FASB) apparently will decide by late 1986 on a final draft of an amendment to SFAS-71. The proposed change in SFAS-71, particularly in regard to PECO, could result in investor perception of higher risk given the need to obtain timely and complete recovery of any phase-in of new plant including a return during the phase-in period. Absent adherence to the new more stringent FASB-71, writedowns could occur. Moreover, the possible change in income tax laws adds uncertainty and could also increase risk to PECO and other utilities.

Q. HAVE YOU REVIEWED INCENTIVE FUEL CLAUSES WHICH ARE CURRENTLY IN EFFECT?

A. Yes. I have studied incentive fuel clauses in two jurisdictions, California and New York. To the best of my knowledge, these two states were first to put in place incentive fuel clauses.

Q. PLEASE DESCRIBE THE INCENTIVE FUEL ADJUSTMENT CLAUSE IN USE IN CALIFORNIA.

A. California, in 1980, established for Southern California Edison Company an Annual Energy Rate (AER) and an Energy Cost Adjustment Clause (ECAC). The AER is similar to what would be called in Pennsylvania fuel recovered through base rates. From the outset the AER was set to recover 2% of estimated future variable fuel and purchased power costs and 100% of expenses related to the management of fuel oil inventory, such as carrying costs. The ECAC, which is similar to the ECR, was set to recover the remaining 98% of variable fuel and purchased power costs. This placed some risk on utility stockholders in that, if actual fuel costs were different from those that were forecast, only 98% of that variance was subject to later recovery.

That procedure was revised by the California Commission in 1982 in Decision 82-12-105, issued on December 22, 1982. This decision revised the AER/ECAC to include a 10%/90% split of variable fuel and purchase power cost. At that time the expenses related to the fuel inventory, which had been totally recovered in the AER, were also given the 10%/90% treatment. The 10%AER/90%ECAC split was characterized by the Commission as a cautious effort to increase stockholders proportion of the risk of fuel related decisions.

Furthermore, in addition to limiting the risk of non-recovery to 10% undercollections, the Commission believed that there should be a further limitation on additional risk placed on shareholders. Therefore, it established a 160 basis point cap on possible losses to stockholders. This cap is on a before-income tax basis.

Moreover, while the California Commission's actions did increase risk to investors, the California Commission also attempted to at least partially offset risk. It is noteworthy that the Commission believed that it was reducing risk to shareholders by also including fuel inventory costs in the 10%/90% split. Previously, all of these costs had been recovered through the AER, and there was a possibility that earnings could be affected by swings in inventory related costs. In addition, it should be kept in mind that there is in California an electric revenue adjustment mechanism (ERAM) which eliminates the risk to the utility of sales swings. When sales and revenues are above or below those which were used to set the revenue requirement, the ERAM adjusts revenues that customers pay accordingly. Such revenue stabilizing mechanism is not in place in Pennsylvania.

In the Southern California Edison proceeding, three other California utilities were directed to participate: Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company. A second phase was set up in which Southern California Gas was excluded and Sierra Pacific added.

Southern California Edison was later used as a benchmark for establishing the AER/ECAC split for the other electric utilities. For the three utilities, the Commission first set the cap. The Commission sought earnings caps which would have similar financial impacts on the three utilities as the 160 basis point cap has on Southern California Edison. It acknowledged that a comparison of one utility to another does not automatically produce an appropriate answer, and that considerable judgment is involved in setting a cap.

Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Sierra Pacific were all judged to be more risky than

Southern California Edison. Therefore, their caps in terms of basis points were all lower.

Utility	Before-Income Tax Return on Common Equity Cap	Approximate After-Income Tax Return on Common Equity Cap
Southern California Edison	1.60%	0.80%
Pacific Gas & Electric Co.	1.40	0.70
San Diego Gas & Electric Co.	1.20	0.60
Sierra Pacific Resources	1.20	0.60

The approximate dollar exposure to investors due to the cap is as follows:

Southern California Edison	$32.0 million
Pacific Gas & Electric Company	$38.4 million
San Diego Gas & Electric Company	$6.7 million
Sierra Pacific Resources	$280 thousand

In setting the percentage distribution between the AER and ECAC, the California Commission relied upon the frequency with which a Company would encounter the limitations imposed by the cap. For instance, it was noted that for Southern California Edison, based on observations of earnings fluctuations, that Company's $32 million would be reached 19% of the time. It sought to achieve the same probability of reaching the cap for the other companies.

The California Commission, in applying an incentive fuel clause to other electric utilities, attempted to attain symmetry among the utilities commensurate with risk. It also attempted to proceed with caution in applying a previously untried, untested and highly problematical ratemaking technique. If this Commission decides to implement an incentive ECR, I recommend that it proceed with the same cautious reserve.

Q. WHAT ARE THE MAJOR DIFFERENCES IN THE NEW YORK APPLICATION OF THE INCENTIVE FUEL ADJUSTMENT CLAUSE FROM THE CALIFORNIA APPLICATION?

A. There are three. First, New York decided not to generically apply the concept to all utilities. It applied it to only one company, Niagara Mohawk Power Corporation. In a generic proceeding in 1980, the New York Public Service Commission decided that there was inadequate record support for a general application. The New York Public Service Commission decided instead to review the fuel adjustment charge on a case-by-case analysis of the operations of each electric utility under its jurisdiction. It chose Niagara Mohawk as the first candidate because of its diverse generating mix. It reasoned, "The diverse generating mix will allow us to examine how costs are affected by changes in the price of many fuel sources, as well as the operating costs and efficiencies of generating units that are fired by different fuels." (Page 9 of Opinion No. 80-24, dated June 18, 1980, Case No. 27137 Re: Investigation of Fuel Adjustment Clauses of Electric Utilities.)

The second difference from California is that the New York Commission included in the incentive fuel clause only variable fuel costs.

Thirdly, the New York Commission adopted a formula which allows Niagara Mohawk to recover 80% of the first $50 million in variation from total fuel cost and 90% of the next $50 million variation. If the variation is greater than $100 million annually, then a 100% pass-through similar to the 100% existing ECR pass-through would apply. The net result is that Niagara Mohawk stockholders are at risk for $15 million in unrecovered fuel costs. I characterize this as a prudent and cautious first step in implementing an incentive fuel clause.

In modifying the fuel clause, the Commission sought not to pose a threat to Niagara Mohawk's financial health. On the other hand, it noted that there were serious allegations of deficiencies in operating practices and felt that some modification was warranted.

Q. IN YOUR OPINION, IS THERE A COMMON ELEMENT IN REGULATORY COMMISSION TREATMENT OF INCENTIVE FUEL CLAUSES FOR THE COMPANIES YOU HAVE STUDIED?

A. Yes. Both Commissions expressed concern about adding to the risk of investing in the utilities to which an incentive fuel clause was being applied. In California, there was the studied effort in installing the incentive fuel clause to avoid adding to the intrinsic risk of investing in the utilities. An effort was made to restrict exposure to loss to the extent that investment risk is not increased. The California Commission relied on quantitative analyses aimed at measuring the impact of the clause on investors' perception of risk. While any such analysis is by its nature judgmental and subjective, the use thereof demonstrates a concern.

The same concern was expressed in New York. New York rejected the contention that an incentive fuel clause should be applied without a detailed study. It decided to apply it on a case-by-case basis. Only in the instance of Niagara Mohawk did it decide to apply it because the record before the Commission indicated that there was substantial room for improvement in Niagara Mohawk's fuel management practices. The New York Commission proceeded to implement the incentive fuel clause in a very cautious manner. Niagara Mohawk investors are exposed only to a $15 million before-income tax loss related to the incentive fuel clause.

Q. HOW DOES THE RISK TO INVESTORS IN PECO COMPARE WITH THE RISK TO INVESTORS IN OTHER COMPANIES THAT HAVE INCENTIVE FUEL ADJUSTMENT CLAUSES?

A. I have made that comparison in Schedules 3 and 4. These schedules display certain indicators of risk of PECO and the other companies I have studied with incentive fuel adjustment clauses. Schedule 3 contains data for PECO. Schedule 4 contains data for the five companies: Niagara Mohawk, Pacific Gas and Electric Company, San Diego Gas and Electric Company, Sierra Pacific Resources, and Southern California Edison Company. In addition, the average of the five companies is contained on page 1 of Schedule 4. It contains: earnings-price ratios, market-to-book ratios, dividend yields, capital structure ratios, earned rate of return on average booked common equity, various measures of coverage and various measures of quality of earnings. The measures of coverage are calculated both including and excluding AFC. Measures of quality of earnings are AFC as a percent of income available for common equity, effective income tax rate, internal cash generation as a percent of gross construction expenditures and common dividend coverage. A review of these indices leads to the inescapable conclusion that PECO is clearly the most risky of the companies having an incentive fuel adjustment clause.

The market based financial ratios all indicate PECO is riskier than the other companies. They demonstrate that the PECO market price of stock is depressed and has been more depressed relative to the stock of the others. The earnings-price ratio shows that only Niagara Mohawk has a higher five-year average, and Pacific Gas and

Electric has the same five-year average as PECO. PECO is higher than both in 1984, and higher than PG&E in 1983. PECO has a lower average market-to-book ratio over the five years. In 1984 and 1983, it is lower than any of the other companies. Its dividend yield is higher throughout the period. These indices indicate that investors in PECO securities require a premium return over the other securities.

In terms of financial risk measured by the common equity ratio, PECO has the lowest common equity ratio of all companies compared, and therefore, the highest degree of financial risk. Only Sierra Pacific Resources has earned less on book common equity, and its coverages are lower.

In comparison to the other companies studied, PECO has very poor quality earnings over the five-year period as shown on Schedules 1 and 2. PECO has averaged 83.5% AFC as a percent of income available for common equity. Therefore, even though its 12.8% average return on booked common equity is only slightly less than the average of other companies, only a small portion of those earnings are cash. It generated less cash in relationship to its construction expenditures. Its common dividend coverage is lowest. By these measures, it is apparent that PECO is less healthy in terms of its cash position than any company having an incentive fuel clause.

I reiterate that the indices shown on Schedules 3 and 4 indicate that PECO is certainly the most risky company having an incentive fuel adjustment clause. Others share this opinion. The basis of my belief is the information shown on Schedule 5. On Schedule 5, I have shown the current bond ratings of PECO and the five companies. As shown on this Schedule, only PECO is at the bottom investment grade rating.

Q. WHAT CONCLUSION DO YOU DRAW FROM SCHEDULES 1, 2 AND 3?

A. If equal treatment is to be afforded, the exposure to which investors in PECO should be subjected because of an incentive fuel adjustment clause should be less than for any of the companies to which such a clause has been applied. This would apply consistent regulatory treatment among the companies.

Q. DO YOU HAVE A SPECIFIC RECOMMENDATION CONCERNING PECO AND AN ECR MODIFICATION?

A. Yes. Because of the experimental nature of the 80/20 proposal and because of PECO's very sub-standard financial starting point, there should be a limitation to the exposure to variation in fuel costs at the outset. I therefore recommend that this Commission follow the precedent established by the California and New York regulatory agencies and incorporate a cap into the incentive ECR formula. This is necessary in order to prevent further downgrading of PECO First Mortgage Bonds and minimize the possibility of an increase in the cost rate for PECO capital, both debt and equity, for the protection of consumers.

Q. WHAT SPECIFIC CAP DO YOU RECOMMEND?

A. I believe the maximum exposure of loss to PECO investors should be an approximated 1/2 of 1% after income tax return on total company common equity. The basis of my belief is 1) at this point PECO is more risky than the other companies whose regulatory agencies have modified full timely ECR recovery in terms of a cap intended to minimize after-income tax impact on return on common equity; 2) PECO coverages are and will remain low for a few years; and 3) a regulatory signal to investors and rating agencies of caution and moderation is needed to avoid a possible higher cost of capital than otherwise.

Q. SINCE THE CAP IS RELATED TO THE ECR WHICH IN TURN IS RELATED TO RETAIL ELECTRIC RATES IN PENNSYLVANIA, WHAT SPECIFIC DOLLAR AMOUNT DO YOU RECOMMEND AS A CAP?

A. My recommendation proceeds, as I previously indicated, from the notion that an impact greater than 1/2 of 1% on the total company common equity is a reasonable yardstick for the reasons that I have cited. PECO's bond rating and investor perception of the risk from a stockholder's view is on a total company basis because each dollar of investment in PECO's various endeavors (retail electric, wholesale electric, gas, steam, etc.) is presumed to be financed in a manner proportionate to the total company. The prospective dollar amount of total company common equity would average approximately $350 million over the course of the next few years. One half of one percent of $350 million is $17.5 million on an after-income tax basis and, based on an assumed income tax rate of approximately 50%, a dollar cap of approximately $35 million is suggested.

Q. WHAT DOES A $35 MILLION CAP REPRESENT WHEN EXPRESSED AS A PERCENT OF THE COMPANY'S RETAIL ELECTRIC RATE BASE CLAIMED IN THIS PROCEEDING?

A. The Company's rate base claim in this proceeding is approximately $6.964 billion. Accordingly, a $35 million cap relative to a $6.964 billion rate base suggests a one half of one percent before-income tax impact on overall rate of return and an after-income tax impact on overall rate of return of approximately 1/4 of 1%, assuming, for the purpose of illustration, a 50% income tax rate.

Q. IS THE $35 MILLION CAP YOU RECOMMEND AS APPROPRIATE FOR PECO MORE OR LESS THAN THE DOLLAR AMOUNT OF CAP EMPLOYED BY EITHER THE CALIFORNIA COMMISSION RELATIVE TO FOUR ELECTRIC COMPANIES OR THE NEW YORK COMPANY WHICH ALSO HAS A CAP IMPOSED BY THE NEW YORK PUBLIC SERVICE COMMISSION?

A. The $35 million cap I recommend for PECO is more than the dollar amount of cap established by either the New York Commission or the California Commission with the exception of Pacific Gas & Electric Company. I previously mentioned that the cap for Niagara Mohawk was $15 million; the cap for Sierra Pacific Resources was $280 thousand; for San Diego Gas & Electric the cap was $6.7 million, and Southern California Edison had a cap of $32.0 million. The cap for Pacific Gas & Electric Company was established at $38.4 million. Undoubtedly, there is a relationship between the size of the company and the magnitude of the cap, although size alone obviously cannot and should not be the sole criteria used to establish a cap. Schedule 5 displays various indices of size relating PECO to the other five companies. In terms of bond rating, PECO is closest to Niagara Mohawk, whose cap was set at $15 million.

I believe a $35 million cap for PECO is as high as prudently possible at this time. A cap more than $35 million would run the risk of an 80% ERC becoming counter productive to consumers as well as investors, particularly for a company whose investors believe the risk is above the industry average at the outset of the ECR modification and with new risks on the horizon such as FASB-71 and an income tax law change.

Admittedly, a $35 million cap is judgmental. However, while an ECR modification may be an appropriate incentive mechanism for the average risk electric, PECO, at the moment, is not an average risk electric and, thus, a cap is an appropriate judgment at this time until PECO can actually experience better achieved results and other uncertainties, such as FASB-71, have been resolved.

Q. IS IT YOUR TESTIMONY THAT THE LIKELY RANGE OF IMPACT ON RETURN ON COMMON EQUITY OCCASIONED BY AN 80/20 MODIFICATION TO THE ECR IS A RANGE OF JUST AN APPROXIMATE 1/2 OF 1% ON TOTAL PECO COMMON EQUITY, OR 1/4 OF 1% ON THE RETAIL ELECTRIC RATE BASE IN PENNSYLVANIA, BOTH ON AN AFTER-INCOME TAX BASIS OR $35 MILLION ON A BEFORE-INCOME TAX BASIS?

A. No. An 80/20 ECR, standing alone, obviously has a greater potential impact, and this is a primary reason for establishing a cap for the <u>initial</u> application of this experimental program. Setting an incentive fuel adjustment clause admittedly is a new procedure, and other Commissions have proceeded cautiously in applying them. I recommend that this Commission do the same. Once experience has been gained with this clause, adjustments can be made as warranted.

Q. WILL THE PRESENCE OF A REASONABLE CAP BE IMPORTANT TO THE INVESTMENT COMMUNITY?

A. Yes. I believe it is imperative to send a signal to the financial community that a change in the ECR which, without question, places the Company at greater risk, will not have undue adverse financial effect because at this time PECO is already considered to be one of the more risky electric companies in the country. That signal must take the form of a cap, or the modification of the ECR could prove counter productive to PECO consumers and investors at this time. Moreover, the Commission itself apparently believes in caps, as evidenced by the fact that it has placed a cap of $3.2 billion on the construction costs relating to Limerick 2. If a cap is in the public interest with respect to the cost of construction of utility plant, fairness it seems would dictate a cap with respect to impact on investors with respect to expenses largely beyond the control of the Company. As a generalization, I believe it is fair to say, and I believe the data I have provided in my exhibits demonstrates, PECO is more investment risky than are the five electric companies included in my study which have implemented changes in their fuel adjustment procedures. Clearly, under such circumstances, a cap of $35 million on a before-income tax basis with respect to financial impact is the maximum cap appropriate.

Finally, for clarification it should be stated that a cap is a two-way street. To the extent there is a reduction in fuel and interchange costs up to but not more than $35 million, stockholders would be afforded an opportunity to experience a better rate of return on rate base and common equity than otherwise. To the extent there is a reduction of more than $35 million, the other side of the $35 million cap coin is a pass-through to consumers of any excess savings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

PECO Statement 18B

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

Further Supplemental
Direct Testimony

of

Thomas P. Hill, Jr.

SUMMARY OF PECO RESPONSE

TO ECR No. 8 ORDER RESPECTING

MODIFICATION OF THE ENERGY COST RATE

December 1985

FURTHER SUPPLEMENTAL DIRECT TESTIMONY
OF THOMAS P. HILL, JR.

Q. Mr. Hill, have you previously presented testimony in this proceeding?

A. Yes, I have presented Direct Testimony (Statement 18) and Supplemental Testimony (Statement 18A) in this proceeding. A full statement of my qualifications, education, employment history and prior testimony experience is set forth in my direct testimony.

Q. What is the purpose of your further supplemental direct testimony?

A. The purpose of my testimony is to present the Company's response to the Commission's Order in the ECR No. 8 Investigation, Docket No. M-840375 et al., entered October 30, 1985 (the "October 30 Order"). The October 30 Order requests the Company to file a modified Energy Cost Rate ("ECR") in which only 80% of total energy costs are subject to after-the-fact reconciliation for over/under collections (the "80%/20% ECR"), and to submit various data as set forth in Appendix B to the Commission's Order.

The Company's response is organized into four statements. Mr. Carroll's supplemental direct testimony (PECO Statement 22A) provides the data and information requested in Appendix B of the October 30 Order, develops and supports the energy cost levels employed in the Company's revised ECR filing, and presents a computer analysis demonstrating the variability of these energy costs. Mr. Gallagher's direct testimony (PECO Statement 30) describes the Company's past and future actions to improve the performance of its generating units. Mr. Brennan's supplemental direct testimony (Statement 28A) analyzes the potential financial impact of the proposed 80%/20% ECR, describes the importance of a fair and balanced ECR to PECO, its customers, and the investment community, and develops the Company's proposed "cap" on the gain or loss resulting from application of an 80%/20% ECR. Finally, my testimony, drawing upon the analyses and recommendations of the other witnesses, presents the Company's overall response to the Commission's Order, including a description of the Company's proposed 80%/20% ECR.

Q. Mr. Hill, please summarize the Company's response to the Commission's Order.

A. Based on the magnitude, variability and uncontrollability of the Company's energy costs, the potential adverse financial impact of non-recovery of a portion of these costs on the Company's already substandard financial condition, and a proper balancing of ratepayer and shareholder interests, the Company believes that the current ECR mechanism should be maintained. Alternatively, if the proposed 80%/20% ECR is adopted, the Company urges the Commission to adopt a reasonable limitation or "cap" on the amount of potential gain or loss to the Company and its customers. Such a cap would be beneficial to both the Company and its customers, would recognize the experimental nature of ECR incentive programs, would appreciably reduce the risk associated with the 80%/20% ECR as perceived by the financial community, and would be consistent with ECR incentive programs adopted in other jurisdictions.

Q. Mr. Hill, please describe the development of the Company's existing ECR and its predecessors.

A. From July 27, 1970 until January 1, 1974, the Company had in place a fuel adjustment mechanism which recovered increases in cost for low sulphur fuel oil burned in Company generating stations located within the City of Philadelphia. This adjustment clause, referred to as the Air Quality Fuel Charge, was adjusted quarterly to reflect changes in fuel oil prices over a pre-established base.

On January 1, 1974, the Company adopted an Electric Fossil Fuel Adjustment Clause ("EFAC") which provided for proper rate reflection of increases or decreases in fossil fuel production costs at Company-owned facilities and in the cost of energy purchased through the Pennsylvania-New Jersey-Maryland Interconnection. This clause worked reasonably well as long as coal and oil costs were approximately equal and there was no nuclear generation. However, with the addition of nuclear power generation to the PECO system and with a growing price disparity between coal and oil prices, the mechanics of the EFAC resulted in a substantial and consistent under-recovery of energy costs for the Company.

On July 1, 1978, PECO and other electric utilities in Pennsylvania instituted the Energy Clause ("EC") which provided for recovery of all increases and decreases in the cost of fuel and energy produced, purchased or delivered. The Energy Clause recognized all sources of generation, including nuclear, and allowed for specific pricing of interchange transactions. The EC, like the EFAC, was a monthly adjustment factor calculated on the basis of historic data and applied prospectively with a billing lag of approximately two months.

Effective June 1, 1980, PECO adopted an Energy Cost Rate to recover changes in the Company's total energy costs. Unlike earlier fuel clauses, the ECR is prospective in nature and is calculated on the basis of estimated data. The ECR results in a charge or credit to the customer which, on a kilowatt-hour (kwh) basis, remains the same for a full twelve-month period. A copy of the Company's current ECR is attached as Schedule 1 to my testimony.

Q. Please describe how the current ECR is computed.

A. The ECR charge is computed annually and is then applied for a twelve-month period unless changed pursuant to mid-term revision procedures set forth in the tariff. The charge is developed by first estimating total energy costs for a prospective effective period. This estimate requires the Company to project a level of generation from each of its production plants and purchases from or sales to other utilities, as well as the anticipated cost of such power purchased or sold. From the total estimated unit cost of energy, i.e., the total cost of power from all sources divided by the total estimated kwh sales, there is deducted the unit cost of energy which will be recovered through base rates. The cost of energy either above or below the amount recovered in base rates is then further adjusted by experienced over/under collection of energy costs during the preceding Section 1307(e) year.

On July 1, 1980, the Company established 28.178 mills per kwh as the base cost of energy to be included in its base rates for electric service. This base cost has remained constant thereafter until the Company's current rate filing in which the Company proposes a 7.355 mill per kwh reduction in the base cost of energy to reflect anticipated energy cost savings from the operation of Limerick 1.

Q. Please explain the fundamental elements of the current ECR charge computation.

A. There are two such elements, which are referred to as the "E" factor and the "C" factor.

The "E" factor reflects prior period over/under collections and can be either a credit or a charge. It represents the difference between energy costs incurred during the "E" factor period and ECR revenues received during the same period. If costs exceeded revenues, an underrecovery occurs, which can be recouped during a prospective ECR application period as an additional charge included in the ECR computation. Conversely, if revenues exceeded costs, the "E" factor is a credit, and is refunded during the prospective period. The "E" factor period is the twelve months ending two months prior to the effective date of a new ECR charge. Under current practice, the ECR recalculation becomes effective April 1, and the "E" factor period therefore is the prior twelve months ending January 31.

The "C" factor is the amount by which total projected energy costs for a prospective twelve-month period divided by total prospective sales (kwh) exceed the cost of energy included in base rates. The "C" factor period is the twelve-month period commencing on the effective date of each annual recalculation of the ECR charge, i.e. April 1 under current ECR practice.

Q. Mr. Hill, what is the purpose of the ECR?

A. Fuel and energy expenses are the largest single operating expense category incurred by a utility in providing service to its customers. For instance, in 1984, this category of expense accounted for almost 45% of the total operating expenses including taxes and depreciation for the Company. Full and timely recovery of these expenses and a mechanism to insure such recovery is therefore essential to the financial viability of PECO.

In addition to their absolute magnitude, energy costs are subject to great variability due to a number of factors beyond PECO's control, and therefore are very difficult to project accurately, particularly over the short-term. For example, as explained more fully in Mr. Carroll's testimony (Statement 22A), PECO's generating and transmission facilities are interconnected with ten other electric utilities in a group collectively known as the Pennsylvania-New Jersey-Maryland ("PJM") Interconnection. Under the PJM Interconnection Agreement, energy flows freely among the member companies, and power is generated from the most economic of the approximately 500 generating units on the PJM system at any point in time regardless of the ownership of the unit. Thus, an important part of PECO's total energy cost projection for any 12-month period is an estimate of the amount of energy PECO will buy from and sell to PJM members and the expected cost of that energy. Any changes from expectations in the operation of major PJM units will affect the Company's total energy costs. The Company's energy costs therefore are dependent not only on the performance of the Company's generating units, but also the performance characteristics of other units operating on the PJM over which PECO has no control. Since interchange costs accounted for approximately 53% of total fuel and interchange costs incurred by PECO in 1984, changes in forecasted interchange expense obviously will have a substantial impact on the Company's energy costs.

Moreover, since PJM is a multi-area power pool, there are transmission limitations on energy transfer within PJM. The Company's energy expense forecast takes these transmission limitations into consideration; however, if a member PJM company requires more interchange energy from outside PJM than projected, transmission limitations would reduce the amount of energy PECO is able to acquire from outside PJM and increase PECO's energy costs, through no fault of the Company.

Absolute changes in fuel prices also significantly affect energy costs and are beyond the Company's control. For example, during the oil embargo of 1974, there was a dramatic escalation in the price of oil due to world economic and political conditions. Similarly, coal prices are based on the results of UMW contracts and short-term variations due to market conditions. Since fuel is purchased solely for the benefit of our customer's energy needs, these cost changes must be passed through in order to maintain the financial viability of the Company.

Changes in electric sales levels also impact PECO's energy costs. Energy requirements are calculated based on "normal" temperatures, weather and economic conditions. When temperature extremes are experienced, by PECO or on PJM (hotter than normal in summer or colder than normal in winter) or when economic growth is greater than expected in PECO's service territory or in the PJM system, there is a corresponding increase in customer energy usage. In order to meet these increased energy requirements, higher operating cost PECO generating units, i.e., oil-fired steam and combustion turbine peaking units, must be operated more frequently, and higher cost PJM energy must be purchased. This higher cost power production and purchases can substantially increase PECO's energy costs.

Regulatory constraints also play a large part in the cost and type of fuel PECO can burn. PECO has the strictest air quality control standards in Pennsylvania, including both the standards of the Environmental Protection Agency and the City of Philadelphia. The combination of these two agency standards require PECO to burn very low sulphur content oil, which increases both the absolute cost and variability of this fuel. In addition, the Company's magnesium oxide facilities are required in order to meet strict air quality control standards at the Company's Philadelphia-area coal-fired units. If these facilities are not operational for any reason, PECO would be required to shut down these coal units. Similarly, NRC requirements, which are beyond PECO's control, have and could continue to affect the level of operations of PECO's nuclear units.

For the reasons set forth above, it is essential for both the Company and its customers that a mechanism be in place to ensure reasonable and timely recovery of energy expenses. Both the Pennsylvania Legislature and this Commission have recognized this need and have allowed for recovery and reconciliation of expenses through an automatic adjustment clause provided under Section 1307 of the Public Utility Code.

Q. Mr. Hill, you have discussed several variables which cause increases in PECO's total cost of energy. Could these same factors also cause decreased energy costs?

A. Yes. A decrease in fossil fuel prices, a decline in sales, and other factors could decrease PECO's energy costs. Under the existing ECR, the benefits of energy cost decreases are fully and automatically flowed through to ratepayers.

Q. Mr. Hill, has the Company performed any analyses to demonstrate the variability of its energy costs?

A. Yes. As explained in Mr. Carroll's testimony, the Company has performed two alternative scenario production cost model runs to demonstrate the potential variability of PECO's energy costs. The results of these analyses are set forth in the following table:

	Projected Total Fuel & Interchange Expenses (Million Dollars)		
	7/86 - 6/87	7/87 - 6/88	7/88-6/89
Base Case	$476.5	$532.9	$511.2
Scenario #1 - low coal generation	$585.4	$670.3	$648.0
Scenario #2 - low nuclear generation	$606.0	$674.2	$743.4

As explained in Mr. Carroll's testimony, the base case of $476.5 million is a reasonable estimate of total energy costs for the period July 1, 1986 - June 30, 1987. Scenario 1 adjusts the base case to reflect a reduction in output of PJM and PECO coal units, a reduction in two-party purchases from midwestern coal plants, low river hydroelectric output, and higher than expected fossil fuel price increases. Under this scenario, PECO's annual energy costs would increase by $108.9-$137.8 million. Scenario 2 is the same as Scenario 1 except that it assumes normal PJM and PECO coal generation, and normal hydroelectric output, but lower than expected

PECO and PJM nuclear generation. This Scenario would produce an increase of $129.5-$232.2 million in PECO's total annual energy costs.

Three points should be emphasized concerning these scenarios. First, as explained by Mr. Carroll, the adjustments made are attributable to events beyond PECO's control and are based upon either actual historic experience or events which could reasonably occur on the PJM system.

Second, as the absolute magnitude of energy costs increases over the three-year period of Mr. Carroll's study, the degree of variability also increases. Specifically, the range of variability increases from a first year level (July 1986 - June 1987) of $108.9-$129.5 million to $137.4-$141.3 million in year two and $136.8-$232.2 million in year three.

Finally, while the analyses performed reflect events which increase PECO's energy costs, similar events could occur which would <u>decrease</u> energy costs, and thereby result in an overrecovery of energy costs by the Company from customers in the absence of the current ECR.

Q. Please describe the potential impact of the above scenarios on the Company if an 80%/20% ECR were adopted.

A. Under an 80%/20% ECR, 20% of the energy cost increases described in the above scenarios would never be recovered even though they were reasonable and necessary costs incurred to provide service to customers and even though the increases were caused by events beyond PECO's control. For Scenario 1 this would be a potential non-recovery of $21.8-$27.6 million, and $25.9-$46.4 million for Scenario 2. This impact of this non-recovery is obviously significant by any standard and is particularly disturbing for both the Company and its customers given the seriously substandard current financial condition of the Company as explained in Mr. Brennan's testimony.

Q. Mr. Hill, are the factors discussed above which cause uncontrolled variability of energy costs expected to continue into the future?

A. Yes. With respect to oil prices, on December 10, 1985, changes in OPEC production and pricing occurred which may have a significant impact on the future price of oil. The Company must now make its best estimate of what the future price of oil will be, at a time when there is great uncertainty as to the level of future oil prices.

With respect to unit operating performance, Mr. Gallagher has stated in his testimony that the Company has accomplished, and will continue to make improvements to its generating stations. These improvements have been reflected in the Company's energy cost projection. However, despite these improvements, it is likely that unforeseen outages will continue to occur on the Company's generating units and the same is true for other PJM generating units. Management of these PJM companies do the best they can to accurately predict future outages on their generating units. However, no one has a crystal ball to precisely predict the future.

Also, weather conditions in PJM and the Company's service territories could deviate substantially from "normal" weather conditions, and the economy may be stronger or weaker than predicted. Finally, while the Company anticipates a reduction in new NRC requirements in the future, acid rain legislation or other legislative or regulatory action could significantly affect the operation of PJM coal and other base load units.

All of the above factors could significantly increase, as well as possibly decrease, the energy costs the Company actually experiences as compared to its best projections. Thus, factors such as the magnitude, variability, uncontrollability and financial impact of energy costs which gave rise to Commission adoption of the ECR remain valid today and continue to support an ECR mechanism which provides full and timely recovery of energy costs for the benefit of the Company and its customers.

Q. Mr. Hill, does the Company have existing incentives to supply the most reliable and economic power to meet its customers' needs?

A. Yes, the Company has several incentives to operate efficiently. As explained in Mr. Carroll's testimony, the economic dispatch system operated by the Company and PJM ensures that customers are receiving the most economic power available at any point of time. In addition, the Company has a strong incentive to minimize rate levels to attract additional sales and to improve its competitive position with competing fuels and power sources. The Company must also satisfy the Commission by operating efficiently to meet various statutory and other requirements. The Commission's 1307(e) audit proceedings, management audits, rate cases and various investigation proceedings all help to ensure that the Company's ratepayers are receiving reliable energy at the lowest possible cost. Finally, PECO's management, as well as its entire workforce, have pride in the job that they do. Meeting customers' needs as economically, efficiently and safely as possible is a major corporate objective of PECO employees. Specific examples of the efforts PECO has undertaken and plans to undertake to improve its generating unit performance are addressed in Mr. Gallagher's testimony (Statement 30).

Q. Mr. Hill, based upon your testimony above and the testimony of Messrs. Carroll, Gallagher and Brennan, what is the Company's position regarding the 80%/20% ECR modification proposed by the Commission's Order?

A. We believe that the existing ECR has operated efficiently and equitably for both the Company and its customers and should be retained in its present form. Energy costs are PECO's single largest expense and are subject to great and uncontrollable variability. The current ECR assures that the Company will recover its energy costs, no more or less, which is fair and equitable to ratepayers and shareholders. A failure to recover actual energy costs could have a significant adverse impact on the Company's already substandard financial condition. As explained by Mr Brennan, an ECR which allows full and timely cost recovery is important to the investment community, and the absence of such a mechanism could increase PECO's risk and its cost of capital to the ultimate detriment of customers. Moreover, PECO has existing incentives to control energy costs, and the Commission has the ability to review, investigate and disallow any energy costs which it believes are unreasonable.

Alternatively, should the Commission proceed to adopt an 80%/20% ECR, the Company believes that a reasonable limitation or "cap" on the amount of gain or loss on the 20% of energy cost variations not subject to after-the-fact reconciliation should be established for the following reasons:

1. A cap would at least partially reflect the fact that a utility's energy costs are highly variable and to a large extent uncontrollable, and the importance of full and

timely recovery of energy costs to a utility and its customers;

2. A cap would reflect the experimental nature of an 80%/20% ECR;

3. A cap would place a reasonable limitation on the gain PECO would receive in the event of lower than expected energy costs, and would give customers an opportunity to receive any gain in excess of the cap;

4. A cap would establish a reasonable limitation on the potential loss to PECO in the event of higher than expected energy costs, and as explained by Mr. Brennan, would be extremely important to the Company and its customers in limiting any increase in risk and capital costs resulting from the adoption of an 80%/20% ECR;

5. A cap would limit disruptive change in rates and therefore would be consistent with principles of gradualism;

6. A cap would be consistent with energy cost incentive programs established by other regulatory commissions, as explained by Mr. Brennan.

Q. What specific "cap" does the Company propose?

A. The "cap" should limit the annual gain or loss in energy cost recovery to $35 million in annual energy expense. The derivation and justification for this cap are set forth in Mr. Brennan's testimony.

Q. Mr. Hill, has the Company prepared a modified ECR to incorporate the 80%/20% provision discussed in the Commission October 30 Order?

A. Yes. Schedule 2 to my testimony contains a revised Energy Cost Rate Factor ("ECRF") to reflect the new 80%/20% ECR. Specifically, the definition of the "E" factor in the ECRF has been changed such that it will include only 80% of the over/under collections from the applicable "E" factor period subject to the $35 million cap.

Q. Mr. Hill, has the Company also prepared a revised ECR calculation for the first year rates set in the Limerick 1 rate proceeding will be in effect?

A. Yes. Schedule 3 is the Company's preliminary calculation of a revised ECR for an approximate twelve-month period beginning June 27, 1986 until June 30, 1987. The proposed effective date of June 27, 1986 reflects the end of the suspension period in this proceeding since the ECRF revision should occur concurrently with the effective date of the new rates established by the Commission in its final Order in this proceeding. After the first year, subsequent ECRF calculations will be effective for a 12-month period beginning July 1. Except for the change in time period, the filing in Schedule 3 is the standard ECR filing which the Company presents to the Commission annually. The projected energy costs in the filing are those developed and presented in Mr. Carroll's additional direct testimony. It should be noted that this filing is preliminary in that it is based upon an estimate of the Company's ECR No. 10 filing which will become effective on April 1, 1986, and an estimate of over/under collections for the 15-month period ending April 30, 1986.

Q. Mr. Hill, how will the Company make the transition from the current ECR mechanism to the ECRF?

A. The Company will file its revised ECR calculation by March 1, 1986, to be effective April 1, 1986, employing existing ECR procedures. Specifically, this filing will reflect expected energy costs for April 1, 1986 - March 31, 1987 (but excluding Limerick 1) and full reconciliation of actual over/under collections for the twelve months ended January 31, 1986. However, this ECR will only be in effect for approximately three months, i.e., until June 27, 1986, when base rates reflecting Limerick 1 are effective. The new ECRF will take effect coincident with the effective date of new base rates reflecting Limerick 1, i.e., on or about June 27, 1986. The "C" factor in this ECRF will reflect anticipated energy costs to be incurred during the period June 27, 1986 - June 30, 1987 (including Limerick 1), and an updated "E" factor for the fifteen-month period ended April 30, 1986. This "E" factor will reflect 100% refund or recoupment of over/under collection in accordance with ECR procedures in effect during that period.

Q. When and how will the 80%/20% split, if approved by the Commission, be reflected in the ECRF "E" factor calculation?

A. The ECRF for the period July 1, 1987 - June 30, 1988 will be based upon an "E" factor period of May 1, 1986 - April 30, 1987, reflecting the normal two-month lag in ECRF year and "E" factor year. This "E" factor will reflect 100% refund/recoupment for the period May 1, 1986 - June 26, 1986 in accordance with established ECR procedures for that period, and 80% refund/recoupment for the June 27, 1986 - April 30, 1987 period in accordance with the new 80%/20% procedure which may become effective at the end of this case.

Q. Mr. Hill, will the filing of the ECRF affect the Company's proposal to reduce the cost of fuel included in base rates to reflect anticipated energy savings from the operation of Limerick 1?

A. No, such a charge is not necessary or appropriate. The proposed 7.355 mill/kwh roll-out of base energy costs represents a reasonable estimate of the average annual energy cost reductions associated with Limerick 1 during the first two years new base rates will be in effect. Since the base rates filed by the Company reflect the capital and operating costs associated with Limerick 1, it is also appropriate to adjust the cost of energy in base rates to reflect the average energy cost savings from Limerick 1 during the initial period new base rates will be in effect. The Company's proposed 7.355 mill/kwh roll-out achieves this result.

The changes proposed by the Company in response to the Commission's October 30 Order deal solely with the Company's ECR and have no impact on base rates or the cost of fuel reflected in base rates. There is therefore no need to revise the base rate filing to reflect proposed revisions to the Company's ECR.

Moreover, it should be noted that the level of fuel costs included in base rates will have no impact on the operation of the 80%/20% ECR procedure since the 80%/20% split applies to <u>all</u> energy costs, including the base cost of fuel. Similarly, in accordance with the Commission's October 30 Order, the total energy costs reflected in the customer's bill (base cost of fuel and ECR) will be stated as one amount on the customer's bill. Therefore, the relative level of energy costs in base rates and the ECR will not affect the level of energy costs shown on the customer's bill.

Finally, the Company's cost of service study (Exhibit WFS-1), allocation of the proposed revenue increase, rate design, and phase-in calculations are all based upon the proposed 7.355 mill/kwh reduction to the base cost of fuel. A change in this roll-out would require the complete recalculation of each of these items, and would be burdensome and unnecessary for the reasons set for the above.

Q. Mr. Hill, does this complete your further supplemental direct testimony?

A. Yes, it does.

ENERGY COST RATE

An energy cost rate shall be applied to each kilowatt-hour supplied under this tariff. This energy cost rate will be determined to the nearest one-thousandth of one mill per kilowatt-hour in acccordance with the formula set forth below and shall be applied to all kilowatt-hours billed during the billing month.

$$ECR = \left[\frac{F}{S_t} - B - \frac{E}{S_a} \right] X \frac{1}{1 - T}$$

The energy cost rate so computed shall be applied to customers' bills for a one-year period during the billing periods of April through March. The Company's proposed annual energy cost rate shall be submitted to the Commission by March 1 of each year and this proposed rate shall become effective for service rendered on or after the following April 1 unless otherwise ordered by the Commission. However, such rate may be revised if the then effective rate is estimated to result in a net over or under collection such that the E for the current twelve-month period ending January 31 will have an absolute value greater than $10 million. Such revision shall become effective 30 days from the date of the revised filing unless otherwise ordered by the Commission.

Where ECR = Energy cost rate in mills per kilowatt-hour to be applied to each kilowatt-hour supplied under this tariff.

F = The estimated energy-related cost of net energy generated in the Company's fossil and nuclear generating stations, excluding the cost of energy generated and sold to other utilities on a firm basis, plus the Company's energy-related cost of energy purchased and net energy interchanged plus the assigned test power costs for the computation year, defined as follows:

Fossil Generation - the costs charged to fuel Accounts 501 and 547 which are computed on basis of the cost of fuel delivered to the generating site at which it is consumed, plus the cost of disposing of solid waste from sulfur oxide removal devices.

Nuclear Generation - the costs charged to fuel Accounts 518 and 521 which are computed on the basis of the costs of such fuel delivered at the generating site at which it is consumed after deducting therefrom the present salvage or reuse value of such fuel.

Net Energy Purchases - the amounts charged or credited to Account 555, excluding demand charges other than those associated with agreements for the purchase of energy at a cost (including associated demand charges) that is less than the cost of obtaining energy from alternative sources.

Net Energy Interchanged - the amounts charged or credited to Account 555, excluding charges or credits for demand related costs.

Test Power - the amounts charged to Account 557 for the value assigned to the energy produced from facilities undergoing operational tests prior to being placed into commercial operation.

The computation year shall be April 1 through March 31 for which the ECR as computed will apply. In projecting the Company's energy costs for the computation year, the estimated cost of energy generated and sold to other utilities on a firm basis and the estimated net effect on the Company's energy costs of generation forecast for the computation year from any unit whose costs are not currently reflected in base rates shall be excluded. When the in-service date of such a unit can be estimated with reasonable certainty, the Company shall file with the Commission no later than 30 days prior to the unit's expected in-service date for an interim revision of the ECR then in effect to reflect the estimated effect of the unit's operation on the Company's energy costs. Such interim revision of the ECR shall not become effective unless and until rates reflecting the unit's base rate revenue requirements become effective by order of the Commission. (C)

(C) Indicates change.

ENERGY COST RATE-Continued

E = Experienced net over or under collection of the cost of energy as of the end of the twelve-month period ending with the preceding January billing period including interest. Interest shall be computed monthly at the appropriate rate as provided in Section 1308(d) of the Public Utility Code from the month the over or under collection occurs to the effective month such over collection is refunded and such under collection is recouped. Customer shall not be liable for interest on net under collections.

S_t= The Company's projected total kilowatt-hour sales to the customers excluding firm sales to other utilities during the computation year.

S_a= The Company's kilowatt-hour sales to which the energy cost rate applies, projected for the computation year.

B = Base energy cost of 28.178 mills per kilowatt-hour.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form.

Minimum bills shall not be reduced by reason of this energy cost rate. This rate shall be applied to all kilowatt-hours supplied and such charge shall be in addition to any minimum applicable.

The Company shall file quarterly reports within thirty (30) days following the conclusion of each computation year quarter. These reports will be in such form as the Commission shall have prescribed. The third quarter report shall be accompanied by a tentative estimate of the energy cost rate for the next computation year.

The application of the energy cost rate shall be subject to continuous review and to audit by the Commission at such intervals as the Commission shall determine. The Commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the energy cost rate and the charges included herein.

If from such audit it shall be determined, by final order entered after notice and hearing, that this energy cost rate has been erroneously or improperly utilized, the Company will rectify such error or impropriety, and in accordance with the terms of the order, apply credits against future energy cost rates for such revenues as shall have been erroneously or improperly collected. The Commission's order shall be subject to the right of appeal.

ENERGY COST RATE FACTOR

All kilowatt-hours supplied under this tariff shall include an energy cost rate factor as determined by the formula below. This energy cost rate factor will be determined to the nearest one-thousandth of one mill per kilowatt-hour in acccordance with the formula set forth below and shall be applied to all kilowatt-hours billed during the billing month.

$$ECRF = \left[\frac{F}{S_t} - B - \frac{E}{S_a} \right] \times \frac{1}{1 - T}$$

The energy cost rate factor so computed shall be applied to customers' bills for a one-year period during the billing periods of July through June except that the first application period will be for the billing periods of June 27, 1986 through June 30, 1987. The Company's proposed annual energy cost rate factor shall be submitted to the Commission by June 1 of each year and this proposed factor shall become effective for service rendered on or after the following July 1 unless otherwise ordered by the Commission.

Where ECRF = Energy cost rate factor in mills per kilowatt-hour to be applied to each kilowatt-hour supplied under this tariff.

F = The estimated energy-related cost of net energy generated in the Company's fossil and nuclear generating stations, excluding the cost of energy generated and sold to other utilities on a firm basis, plus the Company's energy-related cost of energy purchased and net energy interchanged plus the assigned test power costs for the computation year, defined as follows:

Fossil Generation - the costs charged to fuel Accounts 501 and 547 which are computed on basis of the cost of fuel delivered to the generating site at which it is consumed, plus the cost of disposing of solid waste from sulfur oxide removal devices.

Nuclear Generation - the costs charged to fuel Accounts 518 and 521 which are computed on the basis of the costs of such fuel delivered at the generating site at which it is consumed after deducting therefrom the present salvage or reuse value of such fuel.

Net Energy Purchases - the amounts charged or credited to Account 555, excluding demand charges other than those associated with agreements for the purchase of energy at a cost (including associated demand charges) that is less than the cost of obtaining energy from alternative sources.

Net Energy Interchanged - the amounts charged or credited to Account 555, excluding charges or credits for demand related costs.

Test Power - the amounts charged to Account 557 for the value assigned to the energy produced from facilities undergoing operational tests prior to being placed into commercial operation.

The first computation year shall be June 27, 1986 through June 30, 1987, and thereafter shall be July 1 through June 30, for which the ECRF as computed will apply. In projecting the Company's energy costs for the computation year, the estimated cost of energy generated and sold to other utilities on a firm basis and the estimated net effect on the Company's energy costs of generation forecast for the computation year from any unit whose costs are not currently reflected in base rates shall be excluded. When the in-service date of such a unit can be estimated with reasonable certainty, the Company shall file with the Commission no later than 30 days prior to the unit's expected in-service date for an interim revision of the ECRF then in effect to reflect the estimated effect of the unit's operation on the Company's energy costs. Such interim revision of the ECRF shall not become effective unless and until rates reflecting the unit's base rate revenue requirements become effective by order of the Commission.

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Philadelphia Electric Company

ENERGY COST RATE FACTOR - Continued

E = Experienced net over or under collection of the cost of energy determined as follows: Effective June 27, 1986 the Company will reconcile for refund with interest or recovery without interest only 80% of post June 26, 1986 experienced net over or under collection of the cost of energy. The first "E" factor time period will be for the fifteen months ending with the April 1986 billing period with 100% of the experienced net over or under collections reconciled. The second "E" factor time period will be for the twelve months ending with the April 1987 billing period with 100% of the experienced net over or under collections reconciled through June 26, 1986 and 80% of net over or under collections reconciled from June 27, 1986 through April 1987. All subsequent "E" factor periods will be based upon an 80% reconciliation of experienced net over or under collections for a twelve-month period ending with the preceding April billing period. If the 20% of net over or under collections of energy costs, not subject to reconciliation, exceeds an absolute dollar amount of $35 million in any one "E" factor period, the over or under collection in excess of $35 million shall be included in the "E" factor reconciliation. Interest shall be computed monthly at the appropriate rate as provided in Section 1308(d) of the Public Utility Code from the month the over or under collection occurs to the effective month such over collection is refunded and such under collection is recouped. Interest will only be paid on net over- collections subject to reconciliation. Customer shall not be liable for interest on net undercollections.

S_t = The Company's projected total kilowatt-hour sales to the customers excluding firm sales to other utilities during the computation year.

S_a = The Company's kilowatt-hour sales to which the energy cost rate factor applies, projected for the computation year.

B = Base energy cost of 20.823 mills per kilowatt-hour.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form.

Minimum bills shall not be reduced by reason of this energy cost rate factor. This factor shall be applied to all kilowatt-hours supplied and such charge shall be in addition to any minimum applicable.

The Company shall file quarterly reports within thirty (30) days following the conclusion of each computation year quarter. These reports will be in such form as the Commission shall have prescribed. The third quarter report shall be accompanied by a tentative estimate of the energy cost rate factor for the next computation year.

The application of the energy cost rate factor shall be subject to continuous review and to audit by the Commission at such intervals as the Commission shall determine. The Commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the energy cost rate factors and the charges included herein.

If from such audit it shall be determined, by final order entered after notice and hearing, that this energy cost rate factor has been erroneously or improperly utilized, the Company will rectify such error or impropriety, and in accordance with the terms of the order, apply credits against future energy cost rate factors for such revenues as shall have been erroneously or improperly collected. The Commission's order shall be subject to the right of appeal.

0590G-31

ENERGY COST RATE FACTOR

Preliminary

Energy Cost Rate Factor Applicable to Service
Rendered on June 27, 1986 and Thereafter*

Credit: .... (3.076) mills per kilowatt-hour
or
($0.003076) per kilowatt hour

*Use prior to June 27, 1986 will be billed under Energy Cost Rate No. 10

PHILADELPHIA ELECTRIC COMPANY

J. H. AUSTIN, JR., President

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-1
Sheet 1 of 1

PHILADELPHIA ELECTRIC COMPANY

Computation of Energy Cost Rate Factor
Application Period: June 27, 1986 through June 1987
Computation Period: June 27, 1986 through June 1987

1. Energy Cost Rate Factor = $\left(\frac{F}{S_t} - B - \frac{E}{S_a}\right) \times \frac{1}{1-T}$

2. F = Cost of Energy (Schedule E-2, Sheet 2 of 3)		$476,536,383	
3. E = Experienced Net Under-Collection (Sch. E-4, 5 of 5)		($37,110,868)	
4. S_t = Projected Sales for Comp. Period (Sch. E-2, Sh 3 of 3)		28,765,030	MWh
5. S_a = Proj. Retail Sales For Comp. Period (Sch. E-2, Sh 3 of 3) ...		28,151,668	MWh
6. $\frac{F}{S_t} - \frac{E}{S_a}$ Projected Cost per kWh		17.885	m/kWh
7. B = Base Cost	-	20.823	m/kWh
8. Excess Cost (Line 6 - Line 7)		(2.938)	m/kWh
9. $\frac{1}{1-T}$ (T = 4.5%)	x	1.04712	
10. Energy Cost Rate Factor - Calculated (Line 8 x Line 9)		(3.076)	m/kWh

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ELECTRIC GENERATION AND FUEL COST ESTIMATES

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MWH						
OIL-PE STM.	153,000	146,000	146,000	114,000	146,000	186,000
COAL-PE STM.	269,000	316,000	204,000	200,000	185,000	220,000
COAL-MINEMTH	372,000	374,000	365,000	383,000	336,000	339,000
INT.COMB.	17,220	32,910	14,980	7,590	7,810	4,240
TOTAL FOSSIL	811,220	868,910	729,980	704,590	674,810	749,240
MWH NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
NET HYDRO	24,000	(7,000)	1,000	49,000	76,000	144,000
OTHER	0	0	0	0	0	0
RECEIVED PJM	234,000	213,000	301,000	182,000	295,000	294,000
DELIV'D PJM	(128,000)	(174,000)	(95,000)	(80,000)	(104,000)	(98,000)
STEAM-HT PP	500	2,500	2,700	3,900	8,500	16,500
ME,PPL & DPL	16	16	16	16	16	16
2PARTY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
INTCH & PUR	279,516	216,516	382,716	296,916	391,516	420,516
TOTAL OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360

****

$	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
OIL-PE STM	8,291,000	7,906,000	8,068,000	6,730,000	8,006,000	10,020,000
COAL-PE STM	5,537,000	6,504,000	4,206,000	4,175,000	3,884,000	4,661,000
MINEMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
INT.COMB	1,128,000	2,168,800	966,400	475,500	493,500	262,500
TOTAL FOSSIL	20,158,000	21,850,800	18,408,400	16,840,500	17,187,500	19,840,500
(NUCLEAR EXCLUDING INTEREST, BUT INCLUDING OIL)						
NUCLEAR.	12,899,724	12,713,952	10,067,749	9,915,663	9,442,991	9,990,157
OTHER	0	0	0	0	0	0
RECEIVED PJM	7,014,000	7,470,000	9,825,000	7,172,000	9,080,000	10,142,000
DELIV'D PJM	(5,636,000)	(7,447,000)	(4,149,000)	(3,135,000)	(5,235,000)	(4,695,000)
STEAM-HT PP	17,000	87,000	96,000	142,000	307,000	646,000
ME,PPL & DPL	1,196	1,196	1,196	1,196	1,196	1,196
2PARTY TRANS	5,225,000	5,295,000	5,261,000	5,891,000	5,921,000	6,394,000
INTCH & PUR	6,621,196	5,406,196	11,034,196	10,071,196	10,074,196	12,488,196
$-FIN.CHGS	39,678,920	39,970,948	39,510,345	36,827,359	36,704,687	42,318,853
(GAS $ INCLUDED IN COAL-PE STM)						
TOTAL GAS	537,000	632,000	357,000	317,000	108,000	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-2
Sheet 1 of 3

DE[illegible]

ELECTRIC GENERATION AND FUEL COST ESTIMATES

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MWH							
OIL-PE STM.	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
COAL-PE STM.	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
COAL-MINEMTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
INT.COMB.	11,770	12,380	2,610	12,280	2,240	4,230	130,260
TOTAL FOSSIL	1,005,770	760,380	715,610	668,280	739,240	743,230	9,171,260
MWH NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
NET HYDRO	99,000	131,000	213,000	225,000	160,000	79,000	1,194,000
OTHER	0	0	0	0	0	0	0
RECEIVED PJM	136,000	282,000	259,000	418,000	387,000	725,000	3,726,000
DELIV'D PJM	(336,000)	(113,000)	(148,000)	(14,000)	(23,000)	(4,000)	(1,317,000)
STEAM-HT PP	22,200	15,630	12,100	5,100	1,900	2,300	93,800
ME,PPL & DPL	16	16	16	16	16	16	192
2PARTY TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
INTCH & PUR	9,216	350,616	295,116	565,116	506,916	867,316	4,581,992
TOTAL OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494
$							
OIL-PE STM	15,134,000	8,923,000	6,507,000	5,958,000	4,788,000	7,531,000	97,862,000
COAL-PE STM	7,667,000	5,975,000	6,435,000	5,811,000	5,670,000	5,412,000	65,937,000
MINEMOUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
INT.COMB	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200
TOTAL FOSSIL	28,931,000	20,283,700	17,394,800	16,889,000	16,454,000	18,465,000	232,703,200
(NUCLEAR EXCLUDING INTEREST, BUT INCLUDING OIL)							
NUCLEAR.	12,152,686	9,143,637	9,859,519	5,990,617	6,791,025	6,357,607	115,325,327
OTHER	0	0	0	0	0	0	0
RECEIVED PJM	5,123,000	11,222,000	8,415,000	12,257,000	11,702,000	23,748,000	123,170,000
DELIV'D PJM	(17,798,000)	(6,301,000)	(6,655,000)	(764,000)	(725,000)	(237,000)	(62,777,000)
STEAM-HT PP	1,006,000	656,000	434,000	173,000	60,000	78,000	3,702,000
ME,PPL & DPL	1,280	1,280	1,280	1,280	1,280	1,280	14,856
2PARTY TRANS	5,852,000	5,199,000	5,392,000	4,939,000	4,471,000	4,558,000	64,398,000
INTCH & PUR	(5,815,720)	10,777,280	7,587,280	16,606,280	15,509,280	28,148,280	128,507,856
$-FIN.CHGS	35,267,966	40,204,617	34,841,599	39,485,897	38,754,305	52,970,887	476,536,383
(GAS $ INCLUDED IN COAL-PE STM)							
TOTAL GAS	0	0	41,000	596,000	586,000	485,000	3,659,000

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-2
Sheet 2 of 3

Philadelphia Electric Company
System Sales - MWH
Estimated 4/1/86 - 3/31/87

Month	Retail (PECo) (1)	Resale (PECo Plus Interdepartment) (2)	Resale (SE to CP) (3)	Total Projected Sales (4)=(1)+(2)+(3)
July 1986	2,198,414	39,904	6,400	2,244,718
August	2,065,014	38,101	6,400	2,109,515
September	2,241,014	39,103	6,500	2,286,617
October	2,512,014	46,307	7,900	2,566,221
November	2,552,814	45,602	7,200	2,605,616
December	2,498,814	38,705	5,900	2,543,419
January 1987	2,196,814	42,503	7,300	2,246,617
February	2,098,714	38,306	7,500	2,144,520
March	2,389,114	51,410	9,100	2,449,624
April	2,584,214	53,157	9,950	2,647,321
May	2,498,614	44,577	8,430	2,551,621
June	2,316,114	44,477	8,630	2,369,221
12- Month Total	28,151,668	522,152	91,210	28,765,030

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MWH DISTRIBUTION 1 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
OIL						
PE REHEAT OIL						
SCHUYLKILL#1	25,000	21,000	24,000	5,000	22,000	22,000
EDDYSTONE#3	48,000	33,000	40,000	41,000	34,000	42,000
EDDYSTONE#4	43,000	51,000	50,000	36,000	32,000	30,000
CROMBY#2	0	0	0	0	40,000	53,000
DELAWARE#7	20,000	20,000	17,000	19,000	17,000	20,000
DELAWARE#8	17,000	21,000	15,000	13,000	1,000	19,000
MWH R H OIL	153,000	146,000	146,000	114,000	146,000	186,000
PE MARGINAL OIL						
RICHMOND#9	0	0	0	0	0	0
SOUTHWARK#1	0	0	0	0	0	0
SOUTHWARK#2	0	0	0	0	0	0
MWH MARG OIL	0	0	0	0	0	0
REHEAT & MARGINAL OIL MWH OIL	153,000	146,000	146,000	114,000	146,000	186,000
PE COAL						
EDDYSTONE#1	104,000	118,000	115,000	129,000	121,000	106,000
EDDYSTONE#2	115,000	139,000	30,000	0	0	40,000
CROMBY#1	50,000	59,000	59,000	71,000	64,000	74,000
MWH COAL	269,000	316,000	204,000	200,000	165,000	220,000
PHILA. AREA OIL AND COAL. PHILA STEAM	422,000	462,000	350,000	314,000	331,000	406,000
MEMO - STATION TOTALS						
EDDYSTONE	310,000	341,000	235,000	206,000	187,000	218,000
CROMBY	50,000	59,000	59,000	71,000	104,000	127,000
DELAWARE7&8	37,000	41,000	32,000	32,000	18,000	39,000
SOUTHWARK1&2	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 1 of 24

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MWH DISTRIBUTION 1 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
OIL							
PE REHEAT OIL							
SCHUYLKILL#1	45,000	24,000	21,000	14,000	9,000	14,000	246,000
EDDYSTONE#3	67,000	18,000	12,000	24,000	16,000	37,000	412,000
EDDYSTONE#4	66,000	62,000	13,000	12,000	20,000	20,000	435,000
CROMBY#2	44,000	12,000	44,000	32,000	25,000	38,000	288,000
DELAWARE#7	34,000	19,000	12,000	10,000	3,000	12,000	203,000
DELAWARE#8	21,000	21,000	11,000	10,000	5,000	11,000	165,000
MWH R H OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE MARGINAL OIL							
RICHMOND#9	0	0	0	0	0	0	0
SOUTHWARK#1	0	0	0	0	0	0	0
SOUTHWARK#2	0	0	0	0	0	0	0
MWH MARG OIL	0	0	0	0	0	0	0
REHEAT & MARGINAL OIL MWH OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE COAL							
EDDYSTONE#1	124,000	111,000	108,000	117,000	110,000	101,000	1,364,000
EDDYSTONE#2	147,000	98,000	133,000	126,000	130,000	97,000	1,055,000
CROMBY#1	84,000	68,000	55,000	28,000	24,000	53,000	689,000
MWH COAL	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
PHILA. AREA OIL AND COAL. PHILA STEAM	632,000	433,000	409,000	373,000	342,000	383,000	4,857,000
MEMO - STATION TOTALS							
EDDYSTONE	404,000	289,000	266,000	279,000	276,000	255,000	3,266,000
CROMBY	128,000	80,000	99,000	60,000	49,000	91,000	977,000
DELAWARE7&8	55,000	40,000	23,000	20,000	8,000	23,000	368,000
SOUTHWARK1&2	0	0	0	0	0	0	0

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REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 2 of 24

ECR FILING - 7/86 - 6/89

MWH DISTRIBUTION 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MINEMOUTH (PE SHARE)						
KEYSTONE#1	107,000	108,000	95,000	109,000	94,000	90,000
KEYSTONE#2	96,000	84,000	88,000	96,000	85,000	90,000
KEYSTONE STA	203,000	192,000	183,000	205,000	179,000	180,000
CONEMAUGH#1	81,000	96,000	87,000	86,000	79,000	85,000
CONEMAUGH#2	88,000	86,000	95,000	92,000	78,000	74,000
CONEMAUGHSTA	169,000	182,000	182,000	178,000	157,000	159,000
MINEMOUTH	372,000	374,000	365,000	383,000	336,000	339,000
PHILA. AREA OIL & COAL, AND MINEMOUTH COAL.						
FOSSIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
NUCLEAR (PE SHARE)						
PEACH BOT#2	258,117	281,339	252,759	216,140	290,270	208,102
PEACH BOT#3	229,561	272,658	206,693	188,222	132,811	266,502
PCH BOT STA	487,678	553,997	459,452	404,362	423,081	474,604
SALEM#1	282,000	264,000	242,000	247,000	274,000	247,000
SALEM#2	317,000	273,000	136,000	0	0	21,000
SALEM STA	599,000	537,000	378,000	247,000	274,000	268,000
LIM1	663,000	629,000	511,000	643,000	546,000	565,000
LIM2	0	0	0	0	0	0
LIM STA	663,000	629,000	511,000	643,000	546,000	565,000
MWH NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
OTHER (PRECOMMERCIAL)						
LIMERICK 1	0	0	0	0	0	0
LIMERICK 2	0	0	0	0	0	0
OTHER	0	0	0	0	0	0

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REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 3 of 24

ECR FILING - 7/86 - 6/89

MWH DISTRIBUTION 2 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MINEMOUTH (PE SHARE)							
KEYSTONE#1	93,000	90,000	111,000	21,000	84,000	101,000	1,103,000
KEYSTONE#2	81,000	81,000	94,000	92,000	107,000	92,000	1,086,000
KEYSTONE STA	174,000	171,000	205,000	113,000	191,000	193,000	2,189,000
CONEMAUGH#1	96,000	82,000	93,000	87,000	102,000	86,000	1,060,000
CONEMAUGH#2	92,000	62,000	6,000	83,000	102,000	77,000	935,000
CONEMAUGHSTA	188,000	144,000	99,000	170,000	204,000	163,000	1,995,000
MINEMOUTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
PHILA. AREA OIL & COAL, AND MINEMOUTH COAL. FOSSIL STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
NUCLEAR (PE SHARE)							
PEACH BOT#2	276,873	14,290	0	0	248,293	275,980	2,322,163
PEACH BOT#3	259,465	228,681	237,790	246,797	156,899	0	2,426,079
PCH BOT STA	536,338	242,971	237,790	246,797	405,192	275,980	4,748,242
SALEM#1	263,000	257,000	283,000	281,000	300,000	287,000	3,227,000
SALEM#2	255,000	209,000	207,000	275,000	210,000	302,000	2,205,000
SALEM STA	518,000	466,000	490,000	556,000	510,000	589,000	5,432,000
LIM1	561,000	486,000	555,000	0	0	0	5,159,000
LIM2	0	0	0	0	0	0	0
LIM STA	561,000	486,000	555,000	0	0	0	5,159,000
MWH NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
OTHER (PRECOMMERCIAL)							
LIMERICK 1	0	0	0	0	0	0	0
LIMERICK 2	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
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MWH DISTRIBUTION 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
DIESELS						
CROMBY D 1&2	20	0	0	0	100	40
DELAWARE D	20	20	0	20	40	0
SOUTHWARK D	0	0	0	0	0	0
SCHUYLKILL D	0	0	20	10	0	0
PE DIESELS	40	20	20	30	140	40
KEYSTONE D	10	20	20	0	0	0
CONEMAUGH D	10	20	20	0	0	0
DIESEL	60	60	60	30	140	40
GAS TURBINES						
RICH GE CT	2,750	6,170	2,240	1,060	1,770	0
RICH WE CT	0	0	0	0	0	0
RICH NO CT	0	0	0	0	0	0
RICHCT TOTAL	2,750	6,170	2,240	1,060	1,770	0
SOUTHWARK CT	210	870	400	0	0	0
EDDYSTONE CT	280	880	360	0	0	0
DELAWARE CT	270	830	400	0	0	0
SCHUYLKILLCT	110	480	100	0	0	0
CHESTER CT	210	630	300	0	0	0
FALLS CT	360	790	360	0	0	0
MOSER CT	240	840	330	0	0	0
PLY MTG CT	0	0	0	0	0	0
SUBTOTAL	4,430	11,490	4,490	1,060	1,770	0
CROYDON	12,700	21,300	10,400	6,500	5,900	4,200
GAS TURBINES	17,130	32,790	14,890	7,560	7,670	4,200
SALEM CT	30	60	30	0	0	0
TOTAL CT	17,160	32,850	14,920	7,560	7,670	4,200
TOTAL CT AND DIESEL TOTAL IC	17,220	32,910	14,980	7,590	7,810	4,240
SIMPLE CYCLE (INC. SALEM CT) CT TOTAL	4,460	11,550	4,520	1,060	1,770	0

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REFERENCE:
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ECR FILING - 7/86 - 6/89

MWH DISTRIBUTION 3 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
DIESELS							
CROMBY D 1&2	0	60	10	0	0	0	230
DELAWARE D	170	40	0	60	0	0	370
SOUTHWARK D	0	0	0	0	0	0	0
SCHUYLKILL D	40	0	0	0	0	0	70
PE DIESELS	210	100	10	60	0	0	670
KEYSTONE D	0	0	0	10	0	0	60
CONEMAUGH D	0	0	0	10	0	0	60
DIESEL	210	100	10	80	0	0	790
GAS TURBINES							
RICH GE CT	860	280	0	2,830	240	930	19,130
RICH WE CT	0	0	0	0	0	0	0
RICH WD CT	0	0	0	0	0	0	0
RICHCT TOTAL	860	280	0	2,830	240	930	19,130
SOUTHWARK CT	0	0	0	120	0	0	1,600
EDDYSTONE CT	0	0	0	150	0	0	1,670
DELAWARE CT	0	0	0	330	0	0	1,830
SCHUYLKILLCT	0	0	0	30	0	0	720
CHESTER CT	0	0	0	180	0	0	1,320
FALLS CT	0	0	0	220	0	0	1,730
MOSER CT	0	0	0	210	0	0	1,620
PLY MTG CT	0	0	0	0	0	0	0
SUBTOTAL	860	280	0	4,070	240	930	29,620
CROYDON	10,700	12,000	2,600	8,100	2,000	3,300	99,700
GAS TURBINES	11,560	12,280	2,600	12,170	2,240	4,230	129,320
SALEM CT	0	0	0	30	0	0	150
TOTAL CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
TOTAL CT AND DIESEL TOTAL IC	11,770	12,380	2,610	12,280	2,240	4,230	130,260
SIMPLE CYCLE (INC. SALEM CT) CT TOTAL	860	280	0	4,100	240	930	29,770

REFERENCE:
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ECR FILING - 7/86 - 6/89

FUEL COST 1 OF 4

OIL (NO.6 & NO. 2)	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
SCHUYLKILL#1	1,146,000	936,000	1,122,000	227,000	1,015,000	1,059,000
EDDYSTONE1&2	182,000	166,000	186,000	195,000	164,000	210,000
EDDYSTONE3&4	5,185,000	4,852,000	5,147,000	4,643,000	4,086,000	4,460,000
EDDY 1,2,3,4	5,367,000	5,018,000	5,333,000	4,838,000	4,250,000	4,670,000
ED (SULFUR)	0	0	0	0	224,000	424,000
EDDYSTONE	5,367,000	5,018,000	5,333,000	4,838,000	4,474,000	5,094,000
CROMBY#1	16,000	14,000	14,000	11,000	11,000	10,000
CROMBY#2	35,000	35,000	34,000	36,000	1,800,000	2,364,000
CR (SULFUR)	135,000	160,000	159,000	198,000	178,000	205,000
CROMBY	186,000	209,000	207,000	245,000	1,989,000	2,579,000
DELAWARE 7&8	1,727,000	1,903,000	1,565,000	1,618,000	930,000	1,917,000
RICHMOND	0	0	0	0	0	0
SOUTHWARK1&2	0	0	0	0	0	0
TOTAL OIL	8,426,000	8,066,000	8,227,000	6,928,000	8,408,000	10,649,000
COAL						
EDDYSTONE#1	1,880,000	2,122,000	2,086,000	2,376,000	2,222,000	1,956,000
EDDYSTONE#2	2,090,000	2,533,000	553,000	0	0	750,000
EDDYSTONE	3,970,000	4,655,000	2,639,000	2,376,000	2,222,000	2,706,000
CROMBY#1	895,000	1,057,000	1,051,000	1,284,000	1,152,000	1,326,000
TOTAL PECOAL	4,865,000	5,712,000	3,690,000	3,660,000	3,374,000	4,032,000
GAS FOR SCRUBBER						
EDDYSTONE#1	256,000	290,000	282,000	317,000	108,000	0
EDDYSTONE#2	281,000	342,000	75,000	0	0	0
TOTAL GAS	537,000	632,000	357,000	317,000	108,000	0
TOTAL OIL, TOTAL COAL & TOTAL GAS PHILA STEAM	13,828,000	14,410,000	12,274,000	10,905,000	11,890,000	14,681,000

REFERENCE:
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FUEL COST 1 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
OIL (NO.6 & NO. 2)							
SCHUYLKILL#1	2,173,000	1,181,000	1,032,000	689,000	463,000	687,000	11,730,000
EDDYSTONE1&2	227,000	201,000	202,000	171,000	203,000	232,000	2,339,000
EDDYSTONE3&4	7,895,000	4,864,000	1,946,000	2,538,000	2,484,000	3,653,000	51,753,000
EDDY 1,2,3,4	8,122,000	5,065,000	2,148,000	2,709,000	2,687,000	3,885,000	54,092,000
ED (SULFUR)	818,000	629,000	677,000	0	0	0	2,772,000
EDDYSTONE	8,940,000	5,694,000	2,825,000	2,709,000	2,687,000	3,885,000	56,864,000
CROMBY#1	7,000	9,000	16,000	10,000	7,000	16,000	141,000
CROMBY#2	2,035,000	641,000	2,066,000	1,501,000	1,203,000	1,757,000	13,507,000
CR (SULFUR)	246,000	199,000	158,000	80,000	68,000	150,000	1,936,000
CROMBY	2,288,000	849,000	2,240,000	1,591,000	1,278,000	1,923,000	15,584,000
DELAWARE 7&8	2,797,000	2,027,000	1,245,000	1,049,000	428,000	1,186,000	18,392,000
RICHMOND	0	0	0	0	0	0	0
SOUTHWARK1&2	0	0	0	0	0	0	0
TOTAL OIL	16,198,000	9,751,000	7,342,000	6,038,000	4,856,000	7,681,000	102,570,000
COAL							
EDDYSTONE#1	2,312,000	2,056,000	2,031,000	2,200,000	2,087,000	1,921,000	25,249,000
EDDYSTONE#2	2,751,000	1,845,000	2,518,000	2,407,000	2,475,000	1,870,000	19,792,000
EDDYSTONE	5,063,000	3,901,000	4,549,000	4,607,000	4,562,000	3,791,000	45,041,000
CROMBY#1	1,540,000	1,246,000	1,010,000	528,000	454,000	986,000	12,529,000
TOTAL PECOAL	6,603,000	5,147,000	5,559,000	5,135,000	5,016,000	4,777,000	57,570,000
GAS FOR SCRUBBER							
EDDYSTONE#1	0	0	18,000	286,000	268,000	247,000	2,072,000
EDDYSTONE#2	0	0	23,000	310,000	318,000	238,000	1,587,000
TOTAL GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
TOTAL OIL, TOTAL COAL & TOTAL GAS PHILA STEAM	22,801,000	14,898,000	12,942,000	11,769,000	10,458,000	12,943,000	163,799,000

REFERENCE:
ENERGY COST RATE FACTOR
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FUEL COST 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MINEMOUTH (PE SHARE)						
KEYSTN1 COAL	1,348,000	1,361,000	1,196,000	1,404,000	1,208,000	1,160,000
KEYSTN2 COAL	1,213,000	1,054,000	1,112,000	1,225,000	1,094,000	1,155,000
KEYSTONE C	2,561,000	2,415,000	2,308,000	2,629,000	2,302,000	2,315,000
KEYST1&2 OIL	0	17,000	16,000	0	9,000	43,000
KEYSTONE	2,561,000	2,432,000	2,324,000	2,629,000	2,311,000	2,358,000
CON1 COAL	1,260,000	1,491,000	1,352,000	1,357,000	1,249,000	1,345,000
CON2 COAL	1,374,000	1,342,000	1,485,000	1,460,000	1,230,000	1,166,000
CONEMAUGH C	2,634,000	2,833,000	2,837,000	2,817,000	2,479,000	2,511,000
CON1&2 OIL	7,000	7,000	7,000	14,000	14,000	28,000
CONEMAUGH	2,641,000	2,840,000	2,844,000	2,831,000	2,493,000	2,539,000
MINEMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
NUCLEAR (PE SHARE)						
PB2 NUCLEAR	1,786,023	1,946,704	1,748,943	1,495,563	2,008,504	1,439,942
PB3 NUCLEAR	1,739,358	2,065,905	1,566,089	1,426,140	1,006,295	2,019,255
PB2&3INTREST	813,118	786,265	759,413	732,559	705,706	678,854
PB ATOMIC	4,338,499	4,798,874	4,074,445	3,654,262	3,720,505	4,138,051
AUX BOILER	28,778	28,778	27,900	29,698	28,740	29,698
PB DIESEL	4,494	4,494	4,352	4,552	4,404	4,552
SALEM 1	2,086,000	1,953,000	1,795,000	1,831,000	2,033,000	1,831,000
SALEM 2	1,976,000	1,703,000	848,000	0	0	152,000
SLM1INTEREST	481,915	466,511	451,107	435,703	420,299	404,895
SLM2INTEREST	257,184	246,549	235,913	235,913	235,913	508,291
SALEM AUXBLR	0	0	0	0	0	0
SALEM DIESEL	200	200	200	200	200	200
LM1 NUCLEAR	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
LM2 NUCLEAR	0	0	0	0	0	0
LM NUC TOTAL	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
LIMAUXBOILER	43,749	43,749	42,368	44,299	42,869	44,299
LIM DIESEL	7,122	7,122	6,897	7,211	6,979	7,211
NUCLEAR	14,451,941	14,213,277	11,514,182	11,319,838	10,804,909	11,582,197
NOTE: FOR JIM MILLER						
SALEM JC2	0	0	0	0	0	0
OTHER (PRECOMMERCIAL)						
OTHER	0	0	0	0	0	0

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REFERENCE:
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ECR FILING - 7/86 - 6/89

FUEL COST 2 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MINEMOUTH (PE SHARE)							
KEYSTN1 COAL	1,208,000	1,177,000	1,449,000	271,000	1,112,000	1,333,000	14,227,000
KEYSTN2 COAL	1,057,000	1,056,000	1,227,000	1,210,000	1,408,000	1,214,000	14,025,000
KEYSTONE C	2,265,000	2,233,000	2,676,000	1,481,000	2,520,000	2,547,000	28,252,000
KEYST1&2 OIL	27,000	18,000	0	0	18,000	0	148,000
KEYSTONE	2,292,000	2,251,000	2,676,000	1,481,000	2,538,000	2,547,000	28,400,000
CON1 COAL	1,543,000	1,323,000	1,498,000	1,415,000	1,657,000	1,409,000	16,899,000
CON2 COAL	1,478,000	996,000	102,000	1,357,000	1,653,000	1,252,000	14,895,000
CONEMAUGH C	3,021,000	2,319,000	1,600,000	2,772,000	3,310,000	2,661,000	31,794,000
CON1&2 OIL	16,000	8,000	7,000	7,000	0	22,000	137,000
CONEMAUGH	3,037,000	2,327,000	1,607,000	2,779,000	3,310,000	2,683,000	31,931,000
MINEMOUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
NUCLEAR (PE SHARE)							
PB2 NUCLEAR	1,915,803	98,880	0	0	1,798,577	1,999,138	16,238,077
PB3 NUCLEAR	1,965,941	1,732,694	1,802,039	1,875,236	1,192,160	0	18,391,112
PB2&3INTREST	664,921	650,987	969,237	937,582	919,860	902,138	9,520,640
PB ATOMIC	4,546,665	2,482,561	2,771,276	2,812,818	3,910,597	2,901,276	44,149,829
AUX BOILER	31,138	28,124	30,898	29,302	30,278	29,346	352,678
PB DIESEL	4,920	4,444	4,902	4,698	4,856	4,702	55,370
SALEM 1	1,946,000	1,906,000	2,095,000	2,081,000	2,223,000	2,129,000	23,909,000
SALEM 2	1,805,000	1,481,000	1,468,000	1,947,000	1,487,000	2,142,000	15,009,000
SLM1INTEREST	389,491	374,087	358,683	343,279	327,876	312,472	4,766,318
SLM2INTEREST	491,860	475,430	458,999	442,568	426,138	409,707	4,424,465
SALEM AUXBLR	0	0	0	0	0	0	0
SALEM DIESEL	200	200	200	200	200	200	2,400
LM1 NUCLEAR	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
LM2 NUCLEAR	0	0	0	0	0	0	0
LM NUC TOTAL	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
LIMAUXBOILER	47,888	43,254	47,713	45,736	47,260	45,770	538,954
LIM DIESEL	7,796	7,041	7,767	7,445	7,694	7,451	87,736
NUCLEAR	13,698,958	10,644,141	11,646,438	7,714,046	8,464,899	7,981,924	134,036,750
NOTE: FOR JIM MILLER							
SALEM JC2	0	0	0	0	0	0	0
OTHER (PRECOMMERCIAL)							
OTHER	0	0	0	0	0	0	0

REFERENCE:
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FUEL COST 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
DIESELS						
CROMBY D 1&2	1,400	0	0	0	5,800	2,500
DELAWARE D	1,400	1,400	0	1,100	2,500	0
SOUTHWARK D	0	0	0	0	0	0
SCHUYLKILL D	0	0	1,400	400	0	0
KEYSTONE D	800	1,400	1,000	0	200	0
CONEMAUGH D	400	1,000	1,000	0	0	0
DIESEL	4,000	3,800	3,400	1,500	8,500	2,500
GAS TURBINES						
SOUTHWARK CT	17,000	69,000	31,000	0	0	0
EDDYSTONE CT	23,000	72,000	29,000	0	0	0
DELAWARE CT	23,000	67,000	32,000	0	0	0
SCHUYLKILLCT	9,000	38,000	8,000	0	0	0
CHESTER CT	17,000	50,000	23,000	0	0	0
FALLS CT	29,000	63,000	29,000	0	0	0
MOSER CT	20,000	68,000	26,000	0	0	0
PLY MTG CT	0	0	0	0	0	0
RICH GE CT	185,000	412,000	150,000	72,000	120,000	0
RICH WE CT	0	0	0	0	0	0
RICH MO CT	0	0	0	0	0	0
RICHMOND CT	185,000	412,000	150,000	72,000	120,000	0
CROYDON	798,000	1,321,000	632,000	402,000	365,000	260,000
SALEM CT	3,000	5,000	3,000	0	0	0
GAS TURBINES	1,124,000	2,165,000	963,000	474,000	485,000	260,000
TOTAL IC	1,128,000	2,168,800	966,400	475,500	493,500	262,500

REFERENCE:
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ECR FILING - 7/86 - 6/89

FUEL COST 3 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
DIESELS							
CROMBY D 1&2	0	4,000	800	0	0	0	14,500
DELAWARE D	11,300	2,700	0	3,800	0	0	24,200
SOUTHWARK D	0	0	0	0	0	0	0
SCHUYLKILL D	2,700	0	0	0	0	0	4,500
KEYSTONE D	0	0	0	600	0	0	4,000
CONEMAUGH D	0	0	0	600	0	0	3,000
DIESEL	14,000	6,700	800	5,000	0	0	50,200
GAS TURBINES							
SOUTHWARK CT	0	0	0	11,000	0	0	128,000
EDDYSTONE CT	0	0	0	14,000	0	0	138,000
DELAWARE CT	0	0	0	29,000	0	0	151,000
SCHUYLKILLCT	0	0	0	3,000	0	0	58,000
CHESTER CT	0	0	0	17,000	0	0	107,000
FALLS CT	0	0	0	19,000	0	0	140,000
MOSER CT	0	0	0	19,000	0	0	133,000
PLY MTG CT	0	0	0	0	0	0	0
RICH GE CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
RICH ME CT	0	0	0	0	0	0	0
RICH MO CT	0	0	0	0	0	0	0
RICHMOND CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
CROYDON	723,000	780,000	169,000	537,000	131,000	226,000	6,344,000
SALEM CT	0	0	0	2,000	0	0	13,000
GAS TURBINES	787,000	801,000	169,000	855,000	148,000	292,000	8,523,000
TOTAL IC	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200

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REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 1 OF 6 (6 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
EDDYSTONE STATION						
ED1 #6OIL	2,100	2,100	2,300	2,300	2,100	2,300
ED1 SCR OIL	0	0	0	0	7,800	10,700
ED2 #6OIL	2,100	2,100	2,300	2,300	9,900	8,900
ED2 SCR OIL	0	0	0	0	0	4,100
ED1&2 #6OIL	4,200	4,200	4,600	4,600	12,000	11,200
ED12 SCR OIL	0	0	0	0	7,800	14,800
ED3 #6OIL	96,000	70,000	83,000	84,000	73,000	88,000
ED4 #6OIL	88,000	102,000	100,000	76,000	69,000	66,000
ED3&4 #6OIL	184,000	172,000	183,000	160,000	142,000	154,000
----STATION TOTALS---						
ED12 SCR OIL	0	0	0	0	7,800	14,800
ED1234 #6OIL	188,200	176,200	187,600	164,600	154,000	165,200
ED STA #6OIL	188,200	176,200	187,600	164,600	161,800	180,000
CROMBY STATION						
CR1 #6OIL	410	350	360	280	280	270
CR1 SCRUBOIL	5,000	6,000	5,900	7,200	6,400	7,400
CR2 #6OIL	1,310	1,310	1,270	1,310	64,980	85,330
----STATION TOTALS----						
SCRUBBEROIL	5,000	6,000	5,900	7,200	6,400	7,400
CR12 #6OIL	1,720	1,660	1,630	1,590	65,260	85,600
CR STA #6OIL	6,720	7,660	7,530	8,790	71,660	93,000
DEL7 #6OIL	33,000	32,000	29,000	32,000	28,000	33,000
DEL8 #6OIL	28,000	35,000	26,000	23,000	3,000	32,000
DEL STA 6OIL	61,000	67,000	55,000	55,000	31,000	65,000
RICH9 #6OIL	0	0	0	0	0	0
SOUTHWARK STATION						
SWK1 #6OIL	0	0	0	0	0	0
SWK2 #6OIL	0	0	0	0	0	0
SWK STA 6OIL	0	0	0	0	0	0
SCHUY1 #6OIL	41,000	33,000	40,000	8,000	35,000	36,000
TOTAL #6OIL FOR ALL STEAM UNITS:						
STEAM #6OIL	296,920	283,860	290,130	236,390	299,460	374,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
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ECR FILING - 7/86 - 6/89

FUEL BURN 1 OF 6 (6 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
EDDYSTONE STATION							
ED1 #6OIL	2,400	2,000	2,300	2,100	2,300	2,300	26,600
ED1 SCR OIL	12,400	11,100	10,100	0	0	0	52,100
ED2 #6OIL	0	3,300	(100)	2,100	2,300	2,300	37,500
ED2 SCR OIL	14,800	9,800	12,500	0	0	0	41,200
ED1&2 #6OIL	2,400	5,300	2,200	4,200	4,600	4,600	64,100
ED12 SCR OIL	27,200	20,900	22,600	0	0	0	93,300
ED3 #6OIL	131,000	39,000	33,000	54,000	39,000	78,000	868,000
ED4 #6OIL	129,000	121,000	31,000	32,000	45,000	45,000	904,000
ED3&4 #6OIL	260,000	160,000	64,000	86,000	84,000	123,000	1,772,000
----STATION TOTALS---							
ED12 SCR OIL	27,200	20,900	22,600	0	0	0	93,300
ED1234 #6OIL	262,400	165,300	66,200	90,200	88,600	127,600	1,836,100
ED STA #6OIL	289,600	186,200	88,800	90,200	88,600	127,600	1,929,400
CROMBY STATION							
CR1 #6OIL	170	230	380	270	190	380	3,570
CR1 SCRUBOIL	8,500	6,900	5,500	2,800	2,400	5,300	69,300
CR2 #6OIL	70,120	22,040	71,390	53,100	42,520	61,990	476,670
----STATION TOTALS----							
SCRUBBEROIL	8,500	6,900	5,500	2,800	2,400	5,300	69,300
CR12 #6OIL	70,290	22,270	71,770	53,370	42,710	62,370	480,240
CR STA #6OIL	78,790	29,170	77,270	56,170	45,110	67,670	549,540
DEL7 #6OIL	56,000	31,000	20,000	17,000	5,000	21,000	337,000
DEL8 #6OIL	36,000	35,000	20,000	17,000	9,000	18,000	282,000
DEL STA 6OIL	92,000	66,000	40,000	34,000	14,000	39,000	619,000
RICH9 #6OIL	0	0	0	0	0	0	0
SOUTHWARK STATION							
SWK1 #6OIL	0	0	0	0	0	0	0
SWK2 #6OIL	0	0	0	0	0	0	0
SWK STA 6OIL	0	0	0	0	0	0	0
SCHUY1 #6OIL	71,000	39,000	34,000	23,000	16,000	23,000	399,000
TOTAL #6OIL FOR ALL STEAM UNITS:							
STEAM #6OIL	531,390	320,370	240,070	203,370	163,710	257,270	3,496,940

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REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
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ECR FILING - 7/86 - 6/89

FUEL BURN 2 OF 6 (6 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
PEACH BOTTOM AUX. BOILER (PE SHARE ONLY)						
PB2 #6OIL	537	537	520	537	520	537
PB3 #6OIL	537	537	520	537	520	537
PB STA 6OIL	1,074	1,074	1,040	1,074	1,040	1,074
NUCL #6OIL	1,074	1,074	1,040	1,074	1,040	1,074
TOTAL 6OIL FOR ALL ELECTRIC OUTPUT:						
ELECTRIC	297,994	284,934	291,170	237,464	300,500	375,074
STEAM HEAT (SCHUYLKILL TRANSFER, WILLOW & EDISON).						
TRANSFER	26,700	38,500	34,900	42,100	70,100	148,500
WILLOW	0	0	0	0	0	0
EDISON	8,545	2,568	872	892	1,983	4,028
TOTAL STEAM	35,245	41,068	35,772	42,992	72,083	152,528
PEACH BOTTOM AUX. BOILER (PS, AE, DPL SHARES)						
PB2AUX NONPE	727	727	704	727	704	727
PB3AUX NONPE	727	727	704	727	704	727
PB AUX NONPE	1,454	1,454	1,408	1,454	1,408	1,454
TOTAL BARRELS TO BE PURCHASED						
NO 6 OIL	334,693	327,456	328,350	281,910	373,991	529,056

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 2 OF 6 (6 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
PEACH BOTTOM AUX. BOILER (PE SHARE ONLY)							
PB2 #6OIL	537	485	537	520	537	520	6,324
PB3 #6OIL	537	485	537	520	537	520	6,324
PB STA 6OIL	1,074	970	1,074	1,040	1,074	1,040	12,648
NUCL #6OIL	1,074	970	1,074	1,040	1,074	1,040	12,648
TOTAL 6OIL FOR ALL ELECTRIC OUTPUT:							
ELECTRIC	532,464	321,340	241,144	204,410	164,784	258,310	3,509,588
STEAM HEAT (SCHUYLKILL TRANSFER, WILLOW & EDISON).							
TRANSFER	194,800	185,500	170,800	120,800	55,700	43,900	1,132,300
WILLOW	0	0	0	0	0	0	0
EDISON	8,082	17,273	8,306	2,734	994	731	57,008
TOTAL STEAM	202,882	202,773	179,106	123,534	56,694	44,631	1,189,308
PEACH BOTTOM AUX. BOILER (PS, AE, DPL SHARES)							
PB2AUX NONPE	727	657	727	704	727	704	8,562
PB3AUX NONPE	727	657	727	704	727	704	8,562
PB AUX NONPE	1,454	1,314	1,454	1,408	1,454	1,408	17,124
TOTAL BARRELS TO BE PURCHASED							
NO 6 OIL	736,800	525,427	421,704	329,352	222,932	304,349	4,716,020

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
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ECR FILING - 7/86 - 6/89

FUEL BURN 3 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
STEAM STATIONS						
ED1 #2OIL	700	700	1,300	1,300	700	1,300
ED2 #2OIL	1,100	700	700	700	700	1,100
ED3 #2OIL	800	600	700	700	600	800
ED4 #2OIL	700	800	800	600	600	500
ED STA #2OIL	3,300	2,800	3,500	3,300	2,600	3,700
CR1 #2OIL	140	120	120	100	100	90
CR2 #2OIL	0	0	0	0	90	130
CR STA #2OIL	140	120	120	100	190	220
DEL7 #2OIL	590	480	560	560	520	820
DEL8 #2OIL	430	490	420	570	170	740
DEL STA 2OIL	1,020	970	980	1,130	690	1,560
RICH9 #2OIL	0	0	0	0	0	0
SHK1 #2OIL	0	0	0	0	0	0
SHK2 #2OIL	0	0	0	0	0	0
SHK STA 2OIL	0	0	0	0	0	0
SCHUY1 #2OIL	150	110	150	50	110	150
PHILA AREA STEAM UNITS:						
PHL STM 2OIL	4,610	4,000	4,750	4,580	3,590	5,630
MINEMOUTH STATIONS						
KEYST1 #2OIL	0	0	300	0	0	800
KEYST2 #2OIL	0	500	300	0	300	500
KEY STA 2OIL	0	500	600	0	300	1,300
CON1 #2OIL	200	0	0	400	0	400
CON2 #2OIL	0	200	200	0	400	400
CON STA 2OIL	200	200	200	400	400	800
MINEMTH 2OIL	200	700	800	400	700	2,100
PHILA AREA & MINEMTH TOTAL:						
STEAM #2OIL	4,810	4,700	5,550	4,980	4,290	7,730

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 3 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
STEAM STATIONS							
ED1 #2OIL	1,300	600	1,300	700	1,300	1,300	12,500
ED2 #2OIL	1,100	1,400	700	700	700	1,400	11,000
ED3 #2OIL	1,200	300	300	400	300	700	7,400
ED4 #2OIL	1,200	1,000	200	200	300	400	7,300
ED STA #2OIL	4,800	3,300	2,500	2,000	2,600	3,800	38,200
CR1 #2OIL	60	80	130	90	60	130	1,220
CR2 #2OIL	60	70	100	110	100	100	760
CR STA #2OIL	120	150	230	200	160	230	1,980
DEL7 #2OIL	560	480	640	420	130	430	6,190
DEL8 #2OIL	700	510	540	410	320	530	5,830
DEL STA 2OIL	1,260	990	1,180	830	450	960	12,020
RICH9 #2OIL	0	0	0	0	0	0	0
SHK1 #2OIL	0	0	0	0	0	0	0
SHK2 #2OIL	0	0	0	0	0	0	0
SHK STA 2OIL	0	0	0	0	0	0	0
SCHUY1 #2OIL	140	100	140	150	90	140	1,480
PHILA AREA STEAM UNITS:							
PHL STM 2OIL	6,320	4,540	4,050	3,180	3,300	5,130	53,680
MINEMOUTH STATIONS							
KEYST1 #2OIL	300	300	0	0	500	0	2,200
KEYST2 #2OIL	500	300	0	0	0	0	2,400
KEY STA 2OIL	800	600	0	0	500	0	4,600
CON1 #2OIL	200	0	0	0	0	200	1,400
CON2 #2OIL	200	200	200	200	0	400	2,400
CON STA 2OIL	400	200	200	200	0	600	3,600
MINEMTH 2OIL	1,200	800	200	200	500	600	8,400
PHILA AREA & MINEMTH TOTAL:							
STEAM #2OIL	7,520	5,340	4,250	3,380	3,800	5,730	62,080

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 4 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
DIESEL FOR NUCLEAR UNITS						
PEACH BOTTOM (PE SHARE ONLY)						
PB2 #2OIL	67	67	64	67	64	67
PB3 #2OIL	67	67	64	67	64	67
PB STA 2OIL	134	134	128	134	128	134
SALEM1 #2OIL	3	3	3	3	3	3
SALEM2 #2OIL	3	3	3	3	3	3
SAL STA 2OIL	6	6	6	6	6	6
LIM1 AUX BLR	1,300	1,300	1,300	1,300	1,300	1,300
LIM2 AUX BLR	0	0	0	0	0	0
LIM STA AUX	1,300	1,300	1,300	1,300	1,300	1,300
LIM1 DIESEL	210	210	161	210	161	210
LIM2 DIESEL	0	0	0	0	0	0
LIM STA DSL	210	210	161	210	161	210
LIM STA 2OIL	1,510	1,510	1,461	1,510	1,461	1,510
TOTAL FOR ALL NUCLEAR UNITS (PE SHARE)						
NUCL #2OIL	1,650	1,650	1,595	1,650	1,595	1,650
PEACH BOTTOM DIESEL (PS, AE, &DPL SHARES)						
PB2DSL NONPE	91	91	86	91	86	91
PB3DSL NONPE	91	91	86	91	86	91
PB DSL NONPE	182	182	172	182	172	182
LIMERPC AUX	0	0	0	0	0	0
LIMERPC DSL	0	0	0	0	0	0
LIMER PRECOM	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 4 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
DIESEL FOR NUCLEAR UNITS							
PEACH BOTTOM (PE SHARE ONLY)							
PB2 #2OIL	67	60	67	64	67	64	785
PB3 #2OIL	67	60	67	64	67	64	785
PB STA 2OIL	134	120	134	128	134	128	1,570
SALEM1 #2OIL	3	3	3	3	3	3	36
SALEM2 #2OIL	3	3	3	3	3	3	36
SAL STA 2OIL	6	6	6	6	6	6	72
LIM1 AUX BLR	1,300	1,200	1,300	1,300	1,300	1,300	15,500
LIM2 AUX BLR	0	0	0	0	0	0	0
LIM STA AUX	1,300	1,200	1,300	1,300	1,300	1,300	15,500
LIM1 DIESEL	210	164	210	161	210	161	2,278
LIM2 DIESEL	0	0	0	0	0	0	0
LIM STA DSL	210	164	210	161	210	161	2,278
LIM STA 2OIL	1,510	1,364	1,510	1,461	1,510	1,461	17,778
TOTAL FOR ALL NUCLEAR UNITS (PE SHARE)							
NUCL #2OIL	1,650	1,490	1,650	1,595	1,650	1,595	19,420
PEACH BOTTOM DIESEL (PS, AE, &DPL SHARES)							
PB2DSL NONPE	91	82	91	86	91	86	1,063
PB3DSL NONPE	91	82	91	86	91	86	1,063
PB DSL NONPE	182	164	182	172	182	172	2,126
LIMERPC AUX	0	0	0	0	0	0	0
LIMERPC DSL	0	0	0	0	0	0	0
LIMER PRECOM	0	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 5 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
INTERNAL COMBUSTION						
RICH GE CT	5,700	12,700	4,600	2,200	3,600	0
RICH ME CT	0	0	0	0	0	0
RICH MO CT	0	0	0	0	0	0
RICHCT TOTAL	5,700	12,700	4,600	2,200	3,600	0
SOUTHWARK CT	520	2,070	920	0	0	0
EDDYSTONE CT	690	2,140	850	0	0	0
DELAWARE CT	670	2,000	950	0	0	0
SCHUYLKILLCT	270	1,140	230	0	0	0
CHESTER CT	520	1,500	690	0	0	0
FALLS CT	870	1,870	850	0	0	0
MOSER CT	600	2,000	770	0	0	0
PLY MTG CT	0	0	0	0	0	0
PE SUBTOTAL	9,840	25,420	9,860	2,200	3,600	0
CROYDON	25,000	41,000	19,000	12,000	11,000	8,000
PE CT TOTAL	34,840	66,420	28,860	14,200	14,600	8,000
PE DIESELS	80	40	40	40	240	70
PE TOTAL	34,920	66,460	28,900	14,240	14,840	8,070
MINEMOUTH D	40	70	60	0	10	0
SALEM#3	86	171	87	0	0	0
TOTAL IC	35,046	66,701	29,047	14,240	14,850	8,070
STEAM HEAT	8	6	4	4	13	21
TOTAL BARRELS TO BE PURCHASED (EXCLUDES MINEMOUTH & SALEM)						
NO 2 OIL	41,364	72,292	35,415	20,650	20,204	15,547
TOTAL NO 2 OIL FOR PE ELECTRIC SYSTEM (EXCLUDES STEAM HEAT & PB2&3(NONPE))						
TOTAL NO 2	41,506	73,051	36,192	20,870	20,735	17,450

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 5 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
INTERNAL COMBUSTION							
RICH GE CT	1,800	600	0	5,800	500	1,900	39,400
RICH ME CT	0	0	0	0	0	0	0
RICH MO CT	0	0	0	0	0	0	0
RICHCT TOTAL	1,800	600	0	5,800	500	1,900	39,400
SOUTHWARK CT	0	0	0	310	0	0	3,820
EDDYSTONE CT	0	0	0	390	0	0	4,070
DELAWARE CT	0	0	0	800	0	0	4,420
SCHUYLKILLCT	0	0	0	80	0	0	1,720
CHESTER CT	0	0	0	470	0	0	3,180
FALLS CT	0	0	0	510	0	0	4,100
MOSER CT	0	0	0	520	0	0	3,890
PLY MTG CT	0	0	0	0	0	0	0
PE SUBTOTAL	1,800	600	0	8,880	500	1,900	64,600
CROYDON	20,000	22,000	5,000	15,000	4,000	6,000	188,000
PE CT TOTAL	21,800	22,600	5,000	23,880	4,500	7,900	252,600
PE DIESELS	380	170	20	110	0	0	1,190
PE TOTAL	22,180	22,770	5,020	23,990	4,500	7,900	253,790
MINEMOUTH D	0	0	0	40	0	0	220
SALEM#3	0	0	0	69	0	0	413
TOTAL IC	22,180	22,770	5,020	24,099	4,500	7,900	254,423
STEAM HEAT	20	21	27	14	6	3	147
TOTAL BARRELS TO BE PURCHASED (EXCLUDES MINEMOUTH & SALEM)							
NO 2 OIL	30,346	28,979	10,923	28,945	9,632	14,794	329,091
TOTAL NO 2 OIL FOR PE ELECTRIC SYSTEM (EXCLUDES STEAM HEAT & PB2&3(NONPE))							
TOTAL NO 2	31,350	29,600	10,920	29,074	9,950	15,225	335,923

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
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ECR FILING - 7/86 - 6/89

FUEL BURN 6 OF 6 (TONS & MCF)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
TONS OF COAL						
PHILA AREA COAL						
ED1 COAL	38,000	43,000	42,000	47,000	44,000	39,000
ED2 COAL	42,000	51,000	11,000	0	0	15,000
ED STA COAL	80,000	94,000	53,000	47,000	44,000	54,000
CR1 COAL	20,000	24,000	23,000	28,000	25,000	29,000
PE COAL	100,000	118,000	76,000	75,000	69,000	83,000
MINEMOUTH COAL						
CON1 COAL	32,000	38,000	34,000	34,000	31,000	34,000
CON2 COAL	35,000	34,000	38,000	37,000	31,000	29,000
CON STA COAL	67,000	72,000	72,000	71,000	62,000	63,000
KEYST1 COAL	43,000	43,000	38,000	44,000	38,000	36,000
KEYST2 COAL	39,000	34,000	35,000	38,000	34,000	36,000
KEY STA COAL	82,000	77,000	73,000	82,000	72,000	72,000
MINEMTH COAL	149,000	149,000	145,000	153,000	134,000	135,000
TOTAL COAL	249,000	267,000	221,000	228,000	203,000	218,000
MCF OF GAS (EDDYSTONE SCRUBBER RELATED)						
ED1 SCRUBGAS	63,000	72,000	70,000	78,000	27,000	0
ED2 SCRUBGAS	70,000	85,000	18,000	0	0	0
TOTAL GAS	133,000	157,000	88,000	78,000	27,000	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 23 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 6 OF 6 (TONS & MCF)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
TONS OF COAL							
PHILA AREA COAL							
ED1 COAL	45,000	40,000	40,000	43,000	40,000	37,000	498,000
ED2 COAL	54,000	36,000	49,000	47,000	48,000	36,000	389,000
ED STA COAL	99,000	76,000	89,000	90,000	88,000	73,000	887,000
CR1 COAL	33,000	27,000	22,000	11,000	10,000	21,000	273,000
PE COAL	132,000	103,000	111,000	101,000	98,000	94,000	1,160,000
MINEMOUTH COAL							
CON1 COAL	38,000	33,000	37,000	35,000	40,000	34,000	420,000
CON2 COAL	36,000	25,000	2,000	33,000	40,000	31,000	371,000
CON STA COAL	74,000	58,000	39,000	68,000	80,000	65,000	791,000
KEYST1 COAL	37,000	36,000	45,000	8,000	34,000	41,000	443,000
KEYST2 COAL	33,000	33,000	38,000	37,000	43,000	37,000	437,000
KEY STA COAL	70,000	69,000	83,000	45,000	77,000	78,000	880,000
MINEMTH COAL	144,000	127,000	122,000	113,000	157,000	143,000	1,671,000
TOTAL COAL	276,000	230,000	233,000	214,000	255,000	237,000	2,831,000
MCF OF GAS (EDDYSTONE SCRUBBER RELATED)							
ED1 SCRUBGAS	0	0	5,000	71,000	66,000	61,000	513,000
ED2 SCRUBGAS	0	0	6,000	77,000	79,000	59,000	394,000
TOTAL GAS	0	0	11,000	148,000	145,000	120,000	907,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 24 of 24

DEC 20 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
REPORT ENDED JAN'86

	TOTAL SYSTEM SALES KWH 1	CURRENT ENERGY COST MILLS/KWH 2=3/1X 1000	TOTAL ENERGY COST $ 3 (C,D)	ALLOC. FACTOR 4	ENERGY COST PECO RETAIL CUSTOMER $ 5=3X4	RETAIL CUSTOMER SALES KWH 6	ENERGY COST RECOVERED IN BASE RATES $ 7=6XBASE	ENERGY COST OVER BASE $ 8=5-7	ECR FACTOR MILLS/KWH 9(A)	ECR REVENUE $ 10=9X6	OTHER REVENUE $ 11(B)	TOTAL ECR REVENUE $ 12=10+11	O/U RECOVERY $ 13=12-8
FEB'85	2520132788.	29.022	73138782.	0.9741	71244488.	2459350733.	69299585.	1944903.	-1.238635	-3046238.	-414940.	-3461178.	-5406081.
MAR'85	2274670800.	24.812	56439827.	0.9755	55057051.	2216448759.	62455093.	-7398042.	-1.238635	-2745371.	-770448.	-3515819.	3882223.
APR'85	2180772632.	23.188	50567045.	0.9758	49343323.	2127576959.	59950864.	-10607541.	-1.820470	-3873189.	-300059.	-4173248.	6434293.
MAY'85	2133269785.	24.166	51552357.	0.9770	50366653.	2080384413.	58621072.	-8254419.	-2.171623	-4517811.	-222280.	-4740091.	3514328.
JUN'85	2176308704.	25.667	55859617.	0.9775	54602776.	2124535844.	59865171.	-5262395.	-2.184085	-4640167.	505451.	-4134716.	1127679.
JUL'85	2406564458.	32.179	77440332.	0.9812	75984454.	2355394746.	66370313.	9614141.	-2.184085	-5144382.	499633.	-4644749.	-14258890.
AUG'85	2527057557.	28.968	73202854.	0.9807	71790039.	2474913183.	69738104.	2051935.	-2.184085	-5405421.	589708.	-4815713.	-6867648.
SEP'85	2494818450.	24.581	61325386.	0.9735	59700263.	2429767806.	68465997.	-8765734.	-2.184085	-5306819.	507674.	-4799145.	3966589.
OCT'85	2279767534.	27.990	63811405.	0.9816	62637275.	2237250322.	63041240.	-403965.	-2.184085	-4886345.	-280078.	-5166423.	-4762458.
NOV'85	2121277797.	19.724	41839834.	0.9791	40965381.	2073592014.	58429676.	-17464295.	-2.184085	-4528901.	-310982.	-4839883.	12624412.
DEC'85	2397824000.	31.167	74734110.	0.9768	73000279.	2339024000.	65909018.	7091261.	-2.184085	-5108627.	0.	-5108627.	-12199888.
JAN'86	2564421000.	25.191	64600513.	0.9770	63114701.	2502721000.	70521672.	-7406971.	-2.184085	-5466155.	0.	-5466155.	1940816.
YEARLY TOTAL TO DATE	28076885505.		744512062.		727806683.	27420959779	772667805.	-44861122.		-54669426.	-196321.	-54865747.	-10004625.

BASE = 28.178 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE CASE NO. R-811626, PAGE 60.

(C) BEGINING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

(D) BEGINNING JANUARY 25, 1985, SALEM 2 FUEL SAVINGS WILL BE ADDED TO THE TOTAL ENERGY COST.

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 1 of 5

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
REPORT ENDED JAN'86

	O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
FEB'85	-5406081.	13.75	24./12	-1486672.
MAR'85	3882223.	13.75	23./12	1023128.
APR'85	6434293.	13.75	22./12	1621978.
MAY'85	3514328.	14.25	21./12	876385.
JUN'85	1127679.	14.00	20./12	263125.
JUL'85	-14258890.	13.50	19./12	-3047838.
AUG'85	-6867648.	12.75	18./12	-1313438.
SEP'85	3966589.	13.00	17./12	730513.
OCT'85	-4762458.	13.00	16./12	-825493.
NOV'85	12624412.	13.25	15./12	1327430.
DEC'85	-12199888.	12.25	14./12	-1743567.
JAN'86	1940816.	12.25	13./12	257562.
YEARLY TOTAL TO DATE	-10004625.			-2316887.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 2 of 5

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED APR'86

	TOTAL SYSTEM SALES KWH 1	CURRENT ENERGY COST MILLS/KWH 2=3/1X 1000	TOTAL ENERGY COST $ 3 (C)	ALLOC. FACTOR 4	ENERGY COST PECO RETAIL CUSTOMER $ 5=3X4	RETAIL CUSTOMER SALES KWH 6	ENERGY COST RECOVERED IN BASE RATES $ 7=6XBASE	ENERGY COST OVER BASE $ 8=5-7	ECR FACTOR MILLS/KWH 9(A)	ECR REVENUE $ 10=9X6	OTHER REVENUE $ 11(B)	TOTAL ECR REVENUE $ 12=10+11	O/U RECOVERY $ 13=12-8
FEB'86	2444721000.	22.241	54373227.	0.9785	53204203.	2393121000.	67433364.	-14229161.	-2.184085	-5226780.	0.	-5226780.	9002381.
MAR'86	2319721000.	27.615	64059068.	0.9786	62688204.	2267121000.	63882936.	-1194732.	-2.184085	-4951585.	0.	-4951585.	-3756853.
APR'86	2180772632.	20.580	44888280.	0.9791	43950115.	2200618000.	62009014.	-18058899.	-5.464646	-12025598.	0.	-12025598.	6033302.
YEARLY TOTAL TO DATE	6945214632.		163320575.		159842522.	6860860000	193325314.	-33482792.		-22203963.	0.	-22203963.	11278830.

BASE = 28.178 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE CASE NO. R-811626, PAGE 60.

(C) BEGINNING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 3 of 5

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED APR'86

		O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
INTEREST FOR 12 MONTHS ENDED JAN'86					-2316887
	FEB'86	9002381.	12.25	12./12	1102792.
	MAR'86	-3756853.	12.25	11./12	-421863.
	APR'86	6033302.	12.25	10./12	615900.
YEARLY TOTAL TO DATE		11278830.			-1020058.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 4 of 5

DEC 30 1985

Philadelphia Electric Company
Reconciliation of Correction Factor
February 1986 Through April 1986
Estimated

Beginning Balance 1-31-86			($83,174,571)
Amount Recovered by "E" Factor:			
	kWH Sales to Pa. Jurisdictional Customers	"E" Factor Mills/kWh (Excl. GRT)	
Feb '86 & Mar '86	4,660,242,000	6.069025	28,283,125
April 1986	2,200,618,000	2.954510	6,501,748
Overcollection at 4-30-86			11,278,830
Applicable Interest due customer			0
Ending Balance 4-30-86 (To be recouped via "E" factor effective 6-27-86)			($37,110,868)

December 30, 1985
0034/79H

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED JUN'87

	TOTAL SYSTEM SALES KWH 1	CURRENT ENERGY COST MILLS/KWH 2=3/1X 1000	TOTAL ENERGY COST $ 3 (C)	ALLOC. FACTOR 4	ENERGY COST PECO RETAIL CUSTOMER $ 5=3X4	RETAIL CUSTOMER SALES KWH 6	ENERGY COST RECOVERED IN BASE RATES $ 7=6XBASE	ENERGY COST OVER BASE $ 8=5-7	ECR FACTOR MILLS/KWH 9(A)	ECR REVENUE $ 10=9X6	OTHER REVENUE $ 11(B)	TOTAL ECR REVENUE $ 12=10+11	O/U RECOVERY $ 13=12-8
JUL'86	2244718000.	17.677	39678920.	0.9807	38913117.	2198414000.	45777575.	-6864458.	-4.256482	-9357510.	0.	-9357510.	-2493052.
AUG'86	2109515000.	18.948	39970948.	0.9813	39223491.	2065014000.	42999787.	-3776296.	-4.256482	-8789695.	0.	-8789695.	-5013399.
SEP'86	2286617000.	17.279	39510345.	0.9813	38771502.	2241014000.	46664635.	-7893133.	-4.256482	-9538836.	0.	-9538836.	-1645703.
OCT'86	2566221000.	14.351	36827359.	0.9784	36031888.	2512014000.	52307668.	-16275780.	-4.256482	-10692342.	0.	-10692342.	5583438.
NOV'86	2605616000.	14.087	36704687.	0.9803	35981605.	2552814000.	53157246.	-17175641.	-4.256482	-10866007.	0.	-10866007.	6309634.
DEC'86	2543419000.	16.639	42318853.	0.9763	41315896.	2498814000.	52032804.	-10716908.	-4.256482	-10636157.	0.	-10636157.	80751.
JAN'87	2246617000.	15.698	35267966.	0.9767	34446222.	2196814000.	45744258.	-11298036.	-4.256482	-9350699.	0.	-9350699.	1947337.
FEB'87	2144520000.	18.748	40204617.	0.9781	39324136.	2098714000.	43701522.	-4377386.	-4.256482	-8933138.	0.	-8933138.	-4555752.
MAR'87	2449624000.	14.223	34841599.	0.9786	34095989.	2389114000.	49748521.	-15652532.	-4.256482	-10169221.	0.	-10169221.	5483311.
APR'87	2647321000.	14.915	39485897.	0.9792	38664590.	2584214000.	53811088.	-15146498.	-4.256482	-10999660.	0.	-10999660.	4146838.
MAY'87	2551621000.	15.188	38754305.	0.9807	38006347.	2498614000.	52028639.	-14022292.	-4.256482	-10635306.	0.	-10635306.	3386986.
JUN'87	2369221000.	22.358	52970887.	0.9816	51996223.	2316114000.	48228442.	3767781.	-4.256482	-9858498.	0.	-9858498.	-13626279.
YEARLY TOTAL TO DATE	28765030000.		476536383.		466771006.	28151668000	586202185.	-119431179.		-119827069.	0.	-119827069.	-395890.

BASE = 20.823 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION
PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE
CASE NO. R-811626, PAGE 60.

(C) BEGINNING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY
WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-5
Sheet 1 of 2

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED JUN'87

	O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
JUL'86	-2493052.	12.25	20./12	-508998.
AUG'86	-5013399.	12.25	19./12	-972391.
SEP'86	-1645703.	12.25	18./12	-302398.
OCT'86	5583438.	12.25	17./12	968959.
NOV'86	6309634.	12.25	16./12	1030574.
DEC'86	80751.	12.25	15./12	12365.
JAN'87	1947337.	12.25	14./12	278307.
FEB'87	-4555752.	12.25	13./12	-604586.
MAR'87	5483311.	12.25	12./12	671706.
APR'87	4146838.	12.25	11./12	465655.
MAY'87	3386986.	12.25	10./12	345755.
JUN'87	-13626279.	12.25	9./12	-1251914.
YEARLY TOTAL TO DATE	-395890.			133034.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-5
Sheet 2 of 2

Philadelphia Electric Company

STATEMENT OF REASONS

I. The projected ECRF of (3.076) m/kWh is a decrease of 0.448 m/kWh in comparison to the current ECR of (2.628) m/kWh. The reasons for this decrease are as follows:

1. A reduction in the cost of energy of 7.355 m/kWh as a result of the fuel savings anticipated when Limerick Unit #1 begins commercial operation.

2. An undercollection of $37,110,868 applicable to the current ECRF which will be recovered by the correction factor of the proposed rate. This undercollection resulted in a 55.4% decrease to the "E" factor.

December 30, 1985
0034/79H

Residential Bill Analysis

The monthly cost of energy to the average Residential customer (500 kWh) will decrease 0.4% or $0.23 from $58.30 to $58.07.

December 30, 1985
0034/79H

RECEIVED

JAN 29 1986
SECRETARY'S OFFICE
Public Utility Commission

PECO Statement No. 30 (Revised
Docket No. R-850152
1/28/86 Hbg TR

DOCUMENT FOLDER

TESTIMONY OF JOSEPH W. GALLAGHER

Q: Please state your name and business address.

A: Joseph W. Gallagher, 2301 Market St., Philadelphia, PA.

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

A: I am employed by the Philadelphia Electric Company and, since January 1984, I have served as Manager of the Engineering and Research Department. For six years prior, I was Manager of the Electric Production Department.

Q: What is your educational background?

A: I graduated from Villanova University in 1949 with a degree of Bachelor of Electrical Engineering. In 1967, I completed the Executive Development Program at Cornell University and have taken graduate courses at Northwestern and Drexel Universities.

DOCKETED
JAN 30 1986

Q: What are your professional affiliations?

A: I am a licensed professional engineer in Pennsylvania, License #02358E. I was a member of the Operating Committee of the Pennsylvania, New Jersey, Maryland ("PJM") Interconnection for eleven years and was a member of the North American Power Systems Interconnection Committee for four years. I have served on the U.S.-U.S.S.R. Committee on Power System Planning and Operation since 1974 and also serve on the Prime Movers Committee of the Edison Electric Institute, which is concerned with power generation matters. I am also a senior member of the Institute of Electrical and Electronics Engineers and have served on several technical committees of that organization.

Q: Please outline your work experience with the Philadelphia Electric Company.

A: I started with Philadelphia Electric in 1950 as an electrical engineer in the System Planning Division where I worked for approximately 12 years. My duties included planning of the distribution system and the generation and transmission systems and, later, supervision of the long-range generation and transmission branch. After that, I was assigned to the General Administration Department as a staff engineer for about six and one-half years. I was promoted to Assistant Superintendent of the System Operation Division in the Electric Production Department where I worked for five years and was then promoted to Superintendent in the same division for three years. During that time, I was responsible for scheduling production at Philadelphia Electric plants, assuring that they were on-line when needed, directing the load at which the plants were being operated, coordinating plant maintenance and releasing equipment for maintenance, directing the switching and blocking on the transmission system; monitoring transmission line loadings, coordinating generation and transmission outages, and managing service restoration. I served as General Superintendent of the Maintenance Division for one year before being promoted to Manager of the Electric Production Department in April, 1978. My responsibilities, as General Superintendent of Maintenance, included management of the maintenance program of all generating stations, substations, and steam heating system facilities on the Philadelphia Electric Company system.

Q: Please briefly describe the Engineering and Research Department and your responsibilities as Manager of that Department.

A: The Engineering and Research Department is responsible for the planning, engineering, design and construction of all new facilities of the Philadelphia Electric Company. It is responsible for capital modifications of all facilities, load estimating, system planning, and research projects, also. As Manager of the Engineering and Research Department, I administer all of the functions of the Department, subject to the direction and supervision of the Vice President, Engineering and Research. In addition, I review the budgets and cost control systems for all capital work at all facilities, including those partially owned by Philadelphia Electric, but not operated by the Company.

Q: Previously you indicated that, prior to January, 1984, you were the manager of the Electric Production Department. Please briefly describe the Electric Production Department and the responsibilities you had in your prior position as Manager of that Department.

A: The Electric Production Department operates and maintains all of the electrical production facilities operated by Philadelphia Electric, including the Company's nuclear, coal, oil and hydroelectric facilities. It also operates and maintains the Company's steam heating supply stations. The Department is responsible for maintenance work on all generation and supply equipment under Philadelphia Electric's control and coordinates the Company's operations with the PJM Interconnection. As Manager of the Electric Production Department, I administered all of the functions of the Department, subject to the direction and supervision of the Vice President, Electric Production. In addition, I reviewed the operations, budgets, and cost control systems for the electrical production facilities including those partially owned by Philadelphia Electric, but not operated by the Company. These include the Salem nuclear plant, which is operated by Public Service Electric & Gas Company and two coal-fired generating stations (Keystone and Conemaugh) operated by Pennsylvania Electric Company.

Thus, in my positions as the former Manager of the Electric Production Department and now as Manager of the Engineering and Research Department I have had responsibility for, and exercised oversight of, the planning, engineering and implementation of both capital modifications and maintenance work. As I will explain below, these two categories -- capital modifications and maintenance work -- represent the classifications into which all major improvement projects at generating stations are divided for cost approval and implementation purposes.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain improvements Philadelphia Electric Company has made or intends to make in the near future to its baseload generating units to enhance their performance. This information is provided to comply with the following data requirements which are contained in Appendix B to the Pennsylvania Public Utility Commission's Order entered October 30, 1985 at Docket Nos. P-830453, M-840375 and M-FACE8408:

> "The following information and data shall be supplied by the Company ...
>
> (4) <u>Generating Unit Performance Improvements</u>
>
> (i) A report detailing all Company efforts designed to improve system generating efficiency ..."

The Order further explained this data requirement by stating that the information to be provided should focus upon

"Prudent and projected generating unit performance improvements planned or anticipated by the Company."

I also explain major procedure-oriented and personnel-oriented changes and programs as well as capital and maintenance improvements that can have a positive effect on baseload generating performance. I also describe generally the processes and procedures employed by the Company to identify, authorize and implement capital modifications and maintenance work.

I have provided information principally with regard to baseload units. These consist of nuclear units (Peach Bottom 2 and 3 and Salem 1 and 2), the Philadelphia-Area coal-fired units (Eddystone 1 and 2 and Cromby 1), and the mine-mouth coal-fired units (Keystone 1 and 2 and Conemaugh 1 and 2). I should mention that, while the Philadelphia-Area coal-fired units have been categorized as baseload units, they are used by the Company for load-following at times.

Of course, the Company also has oil-fired units, combustion turbines and hydroelectric capacity. However, I have presented information principally for nuclear and coal-fired baseload units because, due to the duration of their operation throughout a year and relatively lower energy costs, "performance improvements" in these units generally have a greater effect on system energy costs.

For purposes of the information I have provided, I interpreted the criteria "system generating efficiency" and "unit performance improvements" as encompassing, in the case of nuclear units, unit availability and, in the case of coal-fired units, unit availability and thermal efficiency. By thermal efficiency, I mean net unit output relative to the fuel input.

Q: Explain how capital modifications and needed maintenance at generating stations is identified, authorized and implemented.

A: As I previously described, the Company's Electric Production Department is responsible for the operation and maintenance of all the Company-operated generating facilities. The Superintendent and Assistant Superintendent at each station, who are typically referred to as "Station Management", are members of that Department. Station Management originates requests for investigation of systems or components that either have failed or are exhibiting what station personnel consider to be deteriorated or unsatisfactory performance. Such investigations are conducted by the Engineering and Research Department's Mechanical or Electrical Engineering Divisions, with input from station personnel or other divisions of the Electric Production Department, as required or deemed desirable. Such investigation is directed to establish the probable cause of the identified failure or unsatisfactory performance, to develop the necessary plan for fixing or improving the system or component studied, to estimate the costs to implement the fix, to make necessary cost-benefit analyses to determine if implementing the design fix is cost-justified and will provide an overall "economic" benefit, and to make a recommendation to Station Management.

If the recommendation is to proceed with the work identified as necessary and cost-justified, Station Management makes a request for authorization to expend funds for the project. If the work entails a capital modification, a Capital Authorization or "CA" is requested. If the necessary work represents maintenance, an Expense Authorization or "EA" is requested. PECO management reviews and approves the requested CAs and EAs, the expenditures for which must be integrated into PECO's overall capital and operating budgets.

After a CA or EA is approved, implementation requires completion of final engineering, scheduling (work that can be done only when a unit is shut down must be fit into the schedule for planned outages), procurement of necessary materials, and preparation of specifications and requests for bids or proposals if outside contractors are to be used.

Work authorized by a CA is generally implemented by the Engineering and Research Department's Construction Division, and work authorized by an EA is generally implemented by the Maintenance Division of the Electric Production Department. However, engineering design and technical supervision is generally provided, in both cases, by the Engineering and Research Department.

Q: What is the Company's participation in the process of authorizing capital and maintenance work at jointly-owned plants that are operated by a joint-owner other than PECO?

A: For jointly-owned plants operated by others, PECO participates in the work review and approval process at the level of the owners' groups, consisting of representatives of each utility having an ownership share in the plant. The operating utilities have procedures similar to PECO's for identifying, analyzing, cost-justifying and approving capital and maintenance work. The strategic decisions for major capital or maintenance programs are submitted to the owners' group for review and approval.

Q: Please describe the information you are submitting in response to the data requirements of the Commission's October 30, 1985 Order.

A: The information is set forth in Schedules 1 and 2 attached to this Statement. Each Schedule corresponds to the categorization of work projects I identified before. That is, Schedule 1 lists capital modifications and Schedule 2 lists maintenance projects. Additionally, Schedule 2 describes personnel-oriented and procedure-oriented changes that are intended or expected to have a beneficial effect on unit performance.

Q: Please refer to Schedule 1 and explain what it shows.

A: Schedule 1 consists of five tables, each containing information about one or more units, as follows:

Table 1	Eddystone 1 and 2
Table 2	Cromby 1
Table 3	Peach Bottom 2 and 3
Table 4	Salem 1 and 2
Table 5	Keystone 1 and 2 and Conemaugh 1 and 2

Each Table shows, for the units it comprehends, capital modifications that will have a positive impact on unit performance. The modifications have been broken out among those completed within the last three years and those projected for substantial completion within the three-year period ending in 1988. Some of the projected work is already in progress.

The first column identifies the project, the second column shows the approximate cost, the third column indicates the area of performance anticipated to be enhanced (availability and/or efficiency), and the last column provides additional information explaining the need for or likely benefit of the work.

I should note that, because the number of modifications for each unit is voluminous, I have shown the cost only for those that exceeded or are anticipated to exceed $1 million.

Some of the projects listed were necessitated for environmental, safety-related, or regulatory compliance. However, the work was included on the schedule because, if not done, the performance of the unit would have been adversely affected. Thus, for example, RHR and recirculation pipe replacement at Peach Bottom 2 was necessitated by availability concerns associated with the generic problem of Intergranular Stress Corrosion Cracking in large-bore piping of Boiling Water Reactors, which was present at Peach Bottom. By replacing the piping with non-susceptible material and by using a design resulting in fewer welds, a potential future reduction in inspections could be expected, which should reduce outage time, reduce the risk of shut-downs due to IGSCC-related problems, and exert a positive effect on future availability. Similarly, installation of SO2 scrubbers at the Philadelphia Area Coal plants have permitted continuation of operation of these units in compliance with environmental standards. It should also be noted that Company efforts to improve performance are not limited to existing operating units. Many of the items identified for Peach Bottom (Table III) have been reflected in the design of the Limerick units or appropriately addressed before operation.

Q: Please refer to Schedule 2 and explain what it shows.

A: Schedule 2 consists of two parts. Part I contains a description of major maintenance work in progress or scheduled for completion within approximately three years that is expected to have a positive effect on unit performance. In lieu of itemization of work packages, to which the maintenance work does not readily lend itself, a brief narrative description of the work to be performed on a system or component is provided.

Part II contains, also, a brief description of major procedure-oriented and personnel-oriented programs implemented by the Company that are expected to enhance or avoid deterioration of unit performance by reducing outage time or that are expected to reduce the cost of operation and maintenance by permitting needed work to be done in a more time and/or cost efficient manner.

Q. Please provide an overview of significant planned improvements affecting performance at the Company's coal and nuclear plants which are intended to address major contributors to unit unavailability.

A. For Peach Bottom, such significant planned improvements include increasing spent fuel storage capacity, -- which together with the refueling platform replacements that are already completed should improve refueling performance, replacing the feedwater heaters, replacing the low pressure turbine rotors on Peach Bottom 2 and 3 (two of three rotors in Peach Bottom 2 were replaced during the outage which ended in July, 1985), and the possible replacement of recirculation and RHR piping in Peach Bottom 3. More detail as to the effect of these improvements is set forth in Schedule 1, Table 3.

For Salem, such significant planned improvements include various pump improvements and replacements, heat exchangers' modifications, and major control and instrumentation modifications, as detailed in Schedule 1, Table 4.

For the Philadelphia-area coal plants such significant planned improvements include, at Cromby 1, replacing the low pressure rotor, modifications to the fly ash disposal system, and installation of micro-processor-based controls, and, at Eddystone, replacing the feedwater heaters at Unit 2, completion of the comprehensive boiler rehabilitation program at Unit 2, installation of micro-processor-based controls at both units, and implementation of computer analysis to identify availability impacting problems with the SO2 scrubbers on both units. More detail as to these items is set forth in Schedule 1, Tables 1 and 2.

For the mine-mouth coal plants, such significant improvements include, at Keystone, replacing economizers, balanced draft conversion, and replacing low pressure feedwater heaters, and, at Conenaugh, replacing the low pressure and high pressure feedwater heaters, replacing air preheater coils, and obtaining spare low and intermediate pressure turbine rotors. In addition, major replacements and modifications of steam generator components (casings, ductwork and pressure vessels) have been in progress and are continuing. These and additional items are explained in Table 1, Schedule 5.

Q. In addition to the specific equipment-based projects you have described, please describe PECO's preventive maintenance program.

A. PECO has in place an extensive preventive maintenance program applicable to all of its generating stations. For example, during each legally-mandated boiler inspection, the boiler is extensively inspected both visually and by non-destructive testing to detect and correct developing problems that could result in forced outages or decreased capacity. Each major steam turbine-generator is totally inspected over a six-year cycle, on a component-per-year basis. All unit generators, major electric motors, and transformers are inspected and subjected to electrical testing on a periodic basis to detect incipient failures. Periodic inspections and overhauls of all major auxiliary systems are made on schedules reflecting the Company's experience in maintaining central generating station equipment. The goal is to reduce the forced outage rate to the maximum feasible and cost-effective extent, considering resource limitations, and to reduce scheduled outages to a minimum cost-effective duration and frequency.

Q. Explain the general principles and criteria that guide PECO's approach to making "unit performance improvements".

A. PECO's general approach is to implement practicable capital or maintenance projects and programs that, based on appropriate analysis and engineering judgment, are reasonably projected to result in overall economic benefit. The pursuit solely of the highest standard of unit performance to the exclusion of other concerns can produce uneconomic results. That is, the capital and maintenance costs incurred to achieve an incremental increase in operating performance can exceed the marginal reduction in energy costs they might produce. In short, work to be done solely to achieve increased unit performance must be cost-justified on the basis of total costs.

These principles are taken into account by PECO in the work authorization procedures I explained before. Specifically work -- other than that mandated by regulatory requirements or health and safety concerns -- is analyzed on a cost benefit basis before expenditures are authorized. The cost-benefit analysis can be more or less formal or sophisticated depending upon the nature, scope and total cost of the work. In some cases, the cost-benefit is clearly justified or unjustified without substantial, written analyses.

Q. Can you explain briefly the quantifiable effects on unit performance of unit improvements and modifications.

A. The effects on total unit performance are difficult to quantify, because unit performance is a function of the dynamic interaction of numerous complex engineering systems. There is one important factor to be remembered, however. Improvements in the performance of a given system or component are not translated into improvements in total unit performance of equal magnitude. Thus, if problems in a given system or component contributed 2 percentage points to the unit's total forced outage rate, correcting those problems will not result in a 2 percentage point reduction in the forced outage rate. The improvement in unit forced outage rate is, generally, less than the improvement in the system's or component's performance. Moreover, as a unit ages and new problems arise, no absolute improvement in performance from past capital modifications and maintenance activities may occur. Rather, capital modifications and maintenance achieve a continuation of existing performance levels or of levels above those that would otherwise be obtained absent those efforts.

Q. Does this conclude your statement?

A. Yes, it does.

SCHEDULE 1

(Revised)

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rotor stress indicators		A	Guide to operator to prevent misoperation that ultimately would result in shortened turbine life
Cold reheat water induction protection system (Unit 2)		A	To prevent equipment damage th would result in forced outage
Chlorine injection modifications		A/E	Prevents organic contamination of condenser--thus improving efficiency--while complying with stricter environmental regulations
Electrostatic precipitator rappers		A/E	Replace and upgrade rappers; reduces particulate scrubbing
Water discharge system modifications		A/E	Improvements to turbine bypass; reduces start-up time, improves availability and reduces start-up fuel
Auxilliary steam back-up		A/E	Improvements that shorten start-up time, improve availability and reduce start-up fuel
Fire protection modifications		A	Localizes and minimizes damage in the event of a fire, thereby reducing possibility of long forced outage due to fire and resulting damage
SO_2/particulate scrubbers	147,430	A	The only alternatives to comply with the Clean Air Act were to retire the unit or convert the units to oil. Installation of scrubbers was the most economical choice to retain that capacity.

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Replace main steam piping (Unit 1)	8,575	A	Piping was at the end of life; in order to retain this unit's capacity, piping had to be replaced.
Coal pile runoff system	1,650	A	Due to environmental law requirements, if this system were not added, the plant would have to be retired or converted to oil.
Turbine stop and control valves	6,420	A	Same as MSP replacement
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace superheater outlet headers (Unit 1)	4,110	A	Material at end of life; to retain this capacity, replacement required.
Develop and implement program to assess high pressure piping integrity		A	To identify possible incipient problems so that effective planning can be developed and repair or replacement coordinated with scheduled outages
Wastewater treatment modifications	1,046	A	To avoid breakdowns that result in environmental violations requiring shutdowns
Feedwater, steam temperature, CC, PD and H.P. boilerfeed pump controls	1,790	A/E	Initial phase of long-term program to upgrade major control systems using microprocessor distributed system technology. To maintain steam pressure and temperature within design parameters. Shortens start-up time and improves thermal performance

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Water induction protection (Units 1 and 2)	$2,740	A	Expanded application of water induction protection to prevent turbine damage
Soot blower control panel replacement		A/E	Replacement and upgrade to allow closer control of steam temperature
ATC (combustion air) drive and control replacement		A/E	Replace and upgrade. Provides more efficient burning of fuel by giving operator control of combustion air
Auxilliary boilers (convert from No. 6 fuel oil to gas firing)	1,500	A/E	Increases availability (because lower maintenance) and improves efficiency
Replace igniters (Units 1 and 2)	1,000	A/E	Reduces start-up time, reduces start-up fuel, increases availability
Replace air tempering coils		A/E	Improves thermal performance
Replace feedwater heaters (Unit 2)	2,135	A/E	Recoup availability and thermal efficiency lost due to tube failures
Air dryers		A	Reduces moisture in compressed air-powered controls; avoids freeze-up
Vibration monitoring		A	Upgrade monitoring of rotating equipment to avoid in-service failures

TABLE 2

CROMBY UNIT 1

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
SO_2/particulate scrubbers	77,032	A	(see explanation of similar item in Table 1)
Replace ignitors		A/E	(see explanation of similar item in Table 1)
Replace economizer		A/E	Improves availability; avoids forced outage due to tube failures
Bag house by-pass duct		A	Allows operation while bag-house is out of service
Replace No. 4 feedwater heater		A/E	(see explanation of similar item in Table 1)
Feedwater, steam temperature, CC controls		A/E	(see explanation of similar item in Table 1)
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Chlorine injection system		A/E	(see explanation of similar item in Table 1)
Demineralizer regeneration pump suction modifications		A	Pump modification to reduce in-service failures
Fire protection modifications		A	(see explanation of similar item in Table 1)
Coal pile run-off system		A	(see explanation of similar item in Table 1)
Purchase of replacement L.P. rotor		A/E	Permits replacement during scheduled outage; updated blade design

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Off-gas system improvements	6,526	A	Eliminated need for pressurized hold-up and compression; increases reliability and decreases maintenance.
Rad-waste storage facility	6,100	A	Increase storage.
Main steam drain valve replacement		A	Facilitates moisture removal from main steam lines; reduces risk of damage to turbine.
Replace recirculation and RHR piping (Unit 2)	31,100	A	Replacement with nonsusceptible material and fewer welds; reduces down-time for future weld ISI and other IGSCC related problems.
Replace safe ends (Unit 2)	4,840	A	Replacement with nonsusceptible material; reduces future IGSCC problems.
Refueling platform modifications		A	Improves efficiency and reliability of fuel handling to reduce critical-path outage time.
Replace 2 of 3 L.P. Turbine Rotors (Unit 2)	12,365	A	Improve reliability, reduce maintenance and inspection requirements.

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace all three L.P. turbine rotors (Unit 3)	5,048	A	Improve future reliability, reduce maintenance; restore performance capability.
Reactor feed pumps recirculation valves		A	
Increase capacity of spent fuel racks	3,830	A	Increases number of cycles of operation with existing spent fuel pool.
Install new recirculation and RHR piping (Unit 3)	30,170	A	(See the explanation of similar item for Unit 2). Decision pending on this major item.
Replace 1 of 3 L.P. turbine rotors (Unit 2)	2,150	A	(See the explanation of similar item above).
Replace feedwater heater		A	(See explanation of similar item in Table 1).
Control room and instrumentation modifications		A	Partially NRC-required; increases operating efficiency.
Plant simulator	4,200	A	Improved operator training will provide greater operator efficiency and reduce errors, improving unit availability and performance. (This facility may be leased rather than Company-owned).
Replace plant process computer	8,400	A/E	Monitors plant conditions providing continuous guidance for plant operation. (This item may be leased rather than Company-owned).

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) (s)	Reason and Effect on Performance A = Availability E)= Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rewind generator (Unit 1)	2,252	A	Generator failed; rewind increases reliability and availability.
Replace generator (Unit 2)	10,350	A	Generator failed, replacement necessary to restore unit availability; increases reliability.
Upgrade moisture separator reheater shells	2,428	A	Improves moisture removal; reduces risk of damage to turbine.
Condensate pump mod. (Unit 2)	1,313	A	Increase reliability, reduces maintenance and increases cycle efficiency.
Retube component cooling heat exchanger		A	Experiencing numerous tube failures; retubing increases reliability and availability.
Upgrade circulating water screen wash.		A	Improves operation and reduces maintenance.
Upgrade H.P. feedwater heater internals		A	Experiencing failures and degraded performance; internals upgrade increases reliability and performance.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Reactor coolant pump motor resistance rings		A	Improve availability, reduce maintenance.
Replace turbine by-pass steam valves		A	Reduces start-up time; improves availability.
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace moisture separator tube bundles	5,473	A	(See the explanation for MSR shell replacement).
Replace RHR sump pumps		A	Old pumps were experiencing high level of failures affecting availability.
Upgrade circulating water pump bearing lubrication pump		A	Improved bearing cooling capability which had become a high maintenance item.
Reactor vessel head quick disconnect tensioner		A	Facilitates head removal; reduces outage time.
Replace service water strainer		A	Existing strainer experiencing high maintenance and poor availability due to corrosion.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace chiller condensers		A	Existing condensers experiencing high rate of tube failures; replacement increases reliability and performance
Replace primary system flow transmitters		A	Existing transmitters were high maintenance items and spare parts not available; replacement increases reliability and performance.
Replace turbine area sump pumps		A	Old pumps experiencing failures affecting availability.
Upgrade plant simulator		A	To reflect plant changes in this important operator-training tool. (Enhance operating performance and minimize operating errors).
Upgrade circulating water pump internals		A	High maintenance and effect on availability; upgrade increases reliability.
Replace service water piping to component cooling heat exchanger		A	High maintenance item -- leaks and failures -- operating availability; upgrade increases reliability.
Turbine-generator supervisory instrumentation		A	Temperature and vibration monitoring; identifies incipien problems; avoids failures, reduces trips during start-up.

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
(Keystone)			
Turbine water induction protection modifications		A	Guide to operator to prevent misoperation that ultimately could result in shortened turbine life
Develop East Valley ash and coal refuse disposal site	1,520	A	Adequate, environmentally-approved waste disposal site required for continued operation
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
(Keystone)			
Replace economizers	4,000	A/E	(see explanation of similar item in Table 2)
Convert boilers to balanced draft	10,745	A/E	Increase availability by reducing casing leaks and hot spots
Replace station computers	1,880	E	To monitor operating parameters and highlight losses that can be corrected
Develop additional ash disposal sites		A	(see similar item explained above)
Electrostatic precipitator modification		E	Improve collecting efficiency; avoids load reductions due to air pollution violations
Replace L.P. feedwater heaters		A/E	(see explanation of similar item in Table 1)
Purchase spare boiler circulating pump		A	Long lead time item; purchased in advance for orderly integration of repair/replacement in scheduled outage and less down-time in event of in-service failure
Replace intermediate reheaters	3,145	A/E	Increase availability by reducing leaks

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	PE COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Wastewater treatment system improvements		A	(see explanation of similar item in Table 1)
Purchase spare boiler feed pump coupling elements		A	Reduce risk of extended outage due to in-service failure or inspection that discovers problem. Long lead-time for procurement.
(Conemaugh)			
Replace H.P. and L.P. Feedwater heaters	1,312	A/E	(see explanation of similar item in Table 1)
Replace station computers	1,852	E	(see explanation of similar item for Keystone)
Develop additional ash disposal sites	1,140	A	(see explanation of similar item for Keystone)
Electrostatic precipitator gas flow improvements		A	(see explanation of similar item for Keystone)
Purchase spare boiler circulating pump		A	(see explanation for similar item for Keystone)
Heat rate monitoring equipment		E	Adjunct to computers and extension of their capabilities

SCHEDULE 2

SCHEDULE 2

I. EQUIPMENT-CENTERED EFFORTS

Rehabilitation of Eddystone 1 and 2 steam generators' pressure vessel parts is being pursued to improve availability. The program on Unit 1 was completed earlier than planned because of the opportunity afforded by the forced outage for replacing main steam piping in 1983-84. The Unit 2 program is scheduled for completion in 1989.

In addition to the rehabilitation programs described above, a comprehensive program was initiated in 1984, in cooperation with the original equipment manufacturer, to study and improve the availability and thermal efficiency of the Eddystone Unit 1 steam generator and auxilliaries. This program includes a review of operating practices and procedures. Results obtained from the Unit 1 program will be applied to Unit 2. Resources permitting, the program is anticipated to be completed by 1989.

A proposal is being considered to apply UNIRAM (computer based) analysis to identify availability problems in Eddystone Unit 1 and 2 scrubbers. A similar program was completed on Cromby Unit 1 scrubber in 1985. Once the problems are identified, a cost-benefit analysis will be performed to determine if and what action should be taken.

Redesign of the boiler feed pump seals on Eddystone Units 1 and 2 is continuing in cooperation with the original equipment manufacturer to minimize forced reductions and to incorporate design improvements growing out of experience.

Major replacements and modifications have been in process since 1982 and are continuing for Conemaugh Units 1 and 2 and Keystone Units 1 and 2 steam generators including castings, ductwork and pressure vessels, intended to improve availability. This work is being done pursuant to a major study performed by a consulting engineering firm to identify areas for improvement. Allied work on controls is also scheduled for the Conemaugh units.

Development and implementation of a comprehensive quality assurance manual and program is in progress at Keystone and Conemaugh. This is expected to result in assurance of high quality workmanship and better reliability of equipment which supports the objectives of better station performance.

Begun in 1985, improvements continue to core/fuel element mechanical/nuclear design leading to economies in fuel cost and increased availability at Peach Bottom. Improved core monitoring is being implemented as well as proposed changes in control rod systems, which are expected to have a positive effect on availability and capacity factor. All these improvements are scheduled in stages, with final completion anticipated in the 1990-1991 time frame. (Additional detail can be provided).

New maintenance tools and equipment are being purchased to improve productivity. Increased use of NDE is designed to improve availability of units through early detection of incipient failures.

II. PERSONNEL-CENTERED EFFORTS

Training of operating and maintenance personnel for Eddystone, Cromby, Keystone and Conemaugh has been upgraded and intensified. An example is the expansion of the training program for fossil and hydro plant operators begun in 1985. The improved and heightened training is designed to reduce operating errors and improve maintenance productivity, leading to increased unit availability and thermal performance.

At PECO, new maintenance mechanic training facilities have been in operation for approximately four years. Improved productivity is expected to result, and the effects should be evident in the near future. PECO is currently undergoing self-evaluation for IMPO accreditation.

III. PROCEDURAL-CENTERED EFFORTS

Planning, scheduling and management of unit outages and routine maintenance, including refueling outages at Peach Bottom and Salem, is being improved by increased use of computer-aided programs, such as CHAMPS (a preventive maintenance program) and MOMS (Maintenance outage managment system) to schedule resources, PICOM (project information and cost management) to track costs and PREMIS (project resource evaluation and management information system) to minimize outage length and levelize manpower requirements. Maintenance planning and scheduling is assisted by MAINPLAN, a computer program designed to optimize resource needs while minimizing outage costs. All the programs utilize procedures and techniques designed to improve site management of outages. The outage planning and management reinforcement began at Peach Bottom in 1980, and 1981 at Eddystone.

The program for tracking and monitoring plant performance and equipment degradation is being intensified at Peach Bottom and increasing emphasis is being placed upon maintaining and improving thermal efficiency.

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January 17, 1986

Jerry Rich, Secretary
Pennsylvania Public Utility
  Commission
North Office Building
Commonwealth & North Streets
P. O. Box 3265
Harrisburg, PA 17120

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

Dear Secretary Rich:

Enclosed are three copies of PECO Statement No. 30 (Revised) with attached Schedules 1 (Revised) and 2, which contain corrections to, and update, the originally-submitted Statement No. 30 and Schedule 1, which were previously distributed. Such revisions typically would be made orally at the time the sponsoring witness is offered for cross-examination. However, for the convenience of the parties, the prepared statement has been modified and redistributed. Also, for the parties' convenience, there are attached hereto summaries of the revisions.

Very truly yours,

Anthony C. DeCusatis

Anthony C. DeCusatis

ACD:vo
ENC:
cc: Honorable Joseph Matuschak
    All Parties of Record

Revisions to Statement 30

References are to
Statement 30 (Revised)

Page	Line	
8	24	added "generally"
9	1	added "generally"
11	7	deleted "safety-related" added "availability"
11	11-12	clarified to indicate design changes
11	16	deleted "changes in" added "installation"
11	17-18	Revised
11	18-23	The last two sentences of the Answer were added.
12	21-23	Revised to indicate that refueling platform mods. are completed
12	22	"replacements" (made plural)
12 13	24 1	Clarification of the number of rotors replaced at each unit.
13	2	added "the possible"

Revisions to Schedule 1

Table 1:

Page 1:	Explanation of the "cold reheat water induction protection system" clarified.
Page 3:	Explanation of "water induction protection" clarified.

Table 3:

Throughout:	The caption of the "Cost" column was revised to clearly indicate that the indicated amount is PECO's share of the total-plant cost.
Page 1:	The explanation of "off-gas system improvements" was revised and the recombiner mod. eliminated because it is part of the off-gas system improvement
	Clarification that main steam drain valve was replaced and not a new installation
Page 1:	Revision to refueling platform mod., that project has been completed.
Page 1 & 2:	Clarification of the number of L.P. Turbine Rotors replaced and scheduled for replacement, and updating costs.
Page 2:	The plant simulator is not yet a completed project. The cost has been updated and the explanation clarified.
Page 2:	Replacement of plant process computer added.

Table 4:

Throughout:	Caption of "Cost" column revised.
Page 3:	Explanation of "upgrade plant simulator" clarified.
	"Turbine-generator supervisory instrumentation"; correct typographical error.

Revisions to Schedule 1 (Continued)

Table 5:

Throughout:	Caption of "Cost" column revised.
Page 1:	"Replace intermediate reheaters" added.

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R-850152
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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

SUPPLEMENTAL DIRECT TESTIMONY
OF
JOHN J. CARROLL

DATA REQUIREMENTS OF ECR NO. 8 ORDER, APPENDIX B
EXPLANATION OF REVISED ECR PROJECTION
ENERGY COST SCENARIO ANALYSES

DOCKETED
JAN 30 1986

December 1985

DOCUMENT
FOLDER

SUPPLEMENTAL DIRECT TESTIMONY OF JOHN J. CARROLL

Q. Are you the same John J. Carroll who previously presented direct testimony in this proceeding?

A. Yes. My direct testimony was previously admitted into evidence as PECO Statement No. 22. A full statement of my qualifications is set forth in that statement.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my testimony is to provide a portion of the Company's response to the Commission's October 30, 1985 Order at Docket No. M-840375 et al, relating to the proposed modification to the Company's Energy Cost Rate ("ECR"). Specifically, my testimony will (1) provide the data and information requested in Appendix B of the Commission's Order, with the exception of Item (4)(i) which is contained in the testimony of Mr. J. W. Gallagher, Statement No. 30, (2) explain and support the Company's estimate of total fuel and interchange expenses for the period July 1, 1986 - June 30, 1987 to be used in the revised ECR; and (3) explain the basis for and results of sensitivity analyses made to examine the impact of unanticipated conditions of cost and energy availability on PECO's future total fuel and interchange expense.

Q. Mr. Carroll, is the Company supplying the information requested in the Commission's October 30 Order?

A. Yes, the information and data requirements set forth in Appendix B of the Commission's October 30 Order are provided in Exhibit JJC-1, with the exception of Item (4)(i) "Generating Unit Performance Improvements", which will be addressed in the testimony of Mr. J. W. Gallagher, Statement No. 30.

Q. Please explain the information and data contained in Exhibit JJC-1.

A. Appendix B to the Commission's October 30 Order requests information and data relating to:

1) Energy Supply Mix and Energy Price Projections and the methodology used by the Company to arrive at these projections.

2) Actual Unit Data Report for PECO's generating units for five historical years and the first year new rates will be in effect.

3) Comparison of historical data to that used or developed for the first year new rates will be in effect.

4) Generating Unit Performance Improvements.

5) Purchased and Interchange Power statistics for the historical period, as well as that developed for the first year new rates will be in effect.

The above data is provided in the section of Exhibit JJC-1 which corresponds to the numbers and subscripts of Appendix B.

Q. Please explain the data provided in response to Items (1) and (1)(i) of Appendix B.

A. Exhibit JJC-1, Items (1) and (1)(i) provide a tabulation of results from the Production Cost model computer run which forms the calculational base for the Company's 1986-87 ECR claim for total fuel and interchange expense. The sheets showing the information requested are as follows:

Pages 1 and 2 of the response list the expected monthly generation and fuel dollars for the different classes of PECO generation by months and source (i.e., coal, nuclear, oil, hydro). These pages also show the quantity and cost of

Interchange Transactions by months from the various sources (PJM, Co-Generation from Steam Heat, Borderline and Two-Party).

Pages 3 through 8 show the generation by individual generating units for each month and pages 9-10 provide a summary by classes.

Pages 11 through 18 list the fuel cost by month for the various generating sources by fuel type and requirement; pages 19-20 summarize fuel costs by types of fuel.

Pages 21 through 22 list the Interchange Transactions by source, the Hydro generation and pumping requirements by months and the Monthly Sales and Company Use requirements.

Q. Mr. Carroll, please describe the information provided by the Company in response to Appendix B, Item (1)(ii).

A. Exhibit JJC-1, Item (1)(ii)(a) provides the requested narrative description of the Company's Production Cost Model. Item (1)(ii)(b) provides the requested Production Cost Model input and output data. Item (1)(ii)(c) describes significant changes to the ProdCost model over the last five years.

Q. Mr. Carroll, in Appendix B, Item 2, "Actual Unit Data Report", the Commission requests certain specific generating unit data. Is this data supplied in Exhibit JJC-1?

A. Most items of specific data requested in Item 2 of Appendix B have been supplied. However, where it was impossible to supply the specific data requested, PECO met with the Commission Staff and proposed the provision of alternative data acceptable to the Staff as maintained by the Company and in a format that is developed by PECO's ProdCost program. I would like to emphasize that all of the data requested in Appendix B is being supplied by the Company, in either the exact form or a comparable form, to that requested.

Q. Mr. Carroll, Appendix B, Item 3 asks the Company to supply a "Comparison of Unit Performance Data Report". Would you explain PECO's response to that data request?

A. Yes, Appendix B, Item 3 requests a comparison of various generating unit operating characteristics for the first year the new ECR is in effect with historic results for the preceding five-year period. This information is provided in Exhibit JJC-1, Item (3)(i). In addition, since any twelve-month period can experience fluctuations in generation mix and fuel cost due to outage cycles, especially at the nuclear plants, the Company has included in its response a three-year projection of the requested performance statistics for PECO's nuclear and fossil fired steam plants.

In reviewing Exhibit JJC-1, Item (3)(i), it should be noted that while individual units may be either high or low in their contribution to the generation mix in any single twelve month period as compared to long or intermediate term historic averages, the units of a collective class of generation will generally average out close to such historic averages over a 36-month period. Therefore, in examining the "Comparison of Unit Data Report" supplied in Appendix B, Item (3)(i), it is necessary to not only examine how a particular unit in a particular year compared to its history, but also how a class of generation over time compares to historic levels.

For example, the nature and extent of planned outages at coal units depend upon the scope of maintenance and other work scheduled for a particular outage, and the length of these outages will obviously have a significant impact on the equivalent availability factors for these units in any twelve-month period. Similarly, the Company's nuclear units are on 18-month refueling cycles. Thus, in any given 12-month period a particular unit may have a full refueling outage or no refueling outage at all. The timing of these outages obviously will affect the capacity factor of a particular unit in a particular 12-month period causing it to be above or below a long-term historic average.

Q. Mr. Carroll, please briefly explain the results of the comparison presented in Exhibit JJC-1, Data Request (3)(i).

A. The following summarizes this comparison:

Nuclear Units - The Equivalent Availability Factors and Net Capacity Factors during the first year new rates are in effect are projected to be equal or better for all units with a historical record, i.e., all units except Limerick 1. With respect to Limerick 1, the projected three-year Net Capacity Factor of 61.6% is in line with historic results for other PECO nuclear plants, and is reasonable given that it includes the period in which Limerick 1 is considered an immature unit for purposes of predicting a Forced Outage Rate. It is an industry accepted practice, borne out by years of statistics, that when a new plant is first placed in service the Forced Outage Rate will be higher than the level expected during its mature lifetime. This higher initial rate then decreases over a few years to the average expected over the lifetime. For this reason, we have used a higher Forced Outage Rate for Limerick No. 1 unit during its period being projected than is expected during the mature lifetime. In addition, a major portion of the first end-of-cycle outage for this unit falls within the first year the new ECR is in effect (July 1, 1986 through June 30, 1987). Given these facts, a predicted first-year Net Capacity Factor of 55.8% is reasonable.

Coal Fired Units - The Equivalent Availability Factors for all units, with the exception of Conemaugh No. 2, are better than their history, and this unit shows only a slight decrease in the first year. For the three prospective years, the class is projected to show improvements, primarily due to greater expectations from Eddystone No. 1 and No. 2 units, and small improvement at the other coal fired plants.

Oil Fired Steam Units - The equivalent availability factors for these units are expected, with the exception of Cromby No. 2, to remain high and possibly show some improvement. However, the capacity factors are expected to decrease as a result of increased base load generation. Cromby 2 is predicted to be low in the future test year due to a projected shutdown to permit full operation of the Limerick 1. The three year projection shows Cromby 2 returning to its normally expected level of equivalent availability.

Q. Mr. Carroll, what conclusions can be drawn from the comparison included in Data Request (3)(i) of Exhibit JJC-1?

A. The comparison shown in Data Request (3)(i) of Exhibit JJC-1 demonstrates that the Company has used a reasonable level of expected performance from its nuclear and coal fired base load plants, as well as a reasonable level of expected availability at the oil fired steam units in projecting the total fuel and interchange expenses during the first year new rates will be in effect.

Q. Mr. Carroll, please describe the Company's response to Appendix B, Item 5.

A. Exhibit JJC-1 provides the requested data on purchased and interchange power for the five-year period 6/30/80 - 6/30/85 and for the first year new rates will be in effect.

Q. Mr. Carroll, the Commission's Order, at page 163, requests that the ALJ consider a comparison of PECO's projected unit performance to the historical performance of comparable units by other utilities, as an additional means of evaluating the reasonableness of the Company's projected total fuel and interchange expense included in its revised ECR filing. Has PECO provided historical statistics for comparable units operated by other utilities?

A. Due to the short amount of time between issuance of the Commission's Order and the date required for this filing, as well as the time demands of other important proceedings before the Commission, PECO has not been able to obtain and present meaningful historical data for comparable units operated by other utilities. However, this data collection process has been started and it will be forwarded to the Commission and all parties in this case as soon as it is available.

With respect to the meaningfulness of comparing the projections of future operation of PECO's units to the historic statistics of comparable units operated by other utilities, PECO does not believe there are true comparable units, or at least a sufficient sample of true comparable units, to many if not all of its units, because of the unique operating conditions of size, operating temperature and pressure, fuel type and characteristics, climatic conditions, plant design considerations and environmental and regulatory restrictions. PECO strongly believes that its plants should be compared to their own history, and that future projections should be expected to maintain or show improvement on this history where appropriate. PECO also believes that unique explainable situations that prevent a unit from achieving this goal should be accepted. Thus, PECO believes that comparisons to other unit operating statistics as a measure of the reasonableness of claimed PECO unit operating performance is often of limited value.

However, notwithstanding these comments, PECO is collecting data on similar units for its nuclear and coal plants. With respect to its nuclear units, PECO has tabulated and presented in Schedule 1 to this testimony historical data for comparable units from the NRC "Grey Book". Since this data is collected according to NRC definitions, it cannot be compared to the data submitted in Exhibit JJC-1. This is because the Forced Outage Rate, Forced Outage Hours and Availability Factor calculated for the NRC do not recognize partial outages of the units. The Company is in the process of adjusting the data to a consistent and comparable basis.

With respect to coal-fired units, PECO believes that because its Philadelphia Area Coal units operate with a magnesium oxide S02 removal system, the only plants that are presently using this method of S02 removal, that these plants do not have similar units that represent the total plant, anywhere in the United States.

PECO also believes that because of the unique design and operating conditions of Eddystone No. 1 units, there is no comparable unit operated by another utility. Eddystone No. 1 unit is the only supercritical unit with an operating design pressure of 5,000 psig and an operating design superheater temperature of 1200 degrees Fahrenheit. Similarly, because of the vintage and generation of the control system and cycle design of Eddystone No. 2 unit, only one other plant in the

United States could be considered as a comparable unit operated by another utility. PECO is presently collecting this historical data.

With respect to Cromby No. 1 and the minemouth plants at Keystone and Conemaugh Stations, PECO is in the process of collecting data on similar units.

Q. Mr. Carroll, turning to the second part of your testimony, please summarize the total fuel and interchange expense projections used in the calculation of the Company's revised ECR.

A. PECO is projecting that the total fuel and interchange expenses for the period from July 1, 1986 to June 30, 1987 will be $476,536,383 to supply a total sales projection of 28,700,515 mwh. This amounts to an average fuel cost for the period of 16.604 mills per kwh. These values of expense and sales, as well as all of the other information used in the Production Cost computer run, have been supplied as part of Exhibit JJC-1, Item 1.

Q. Please explain how the Company projected the above-referenced total fuel and interchange expenses used in developing its revised Energy Cost Rate Filing?

A. The Electric Production Department (EP Dept.) is requested to provide the Rate Division with its latest projection of total fuel and interchange expenses that will be incurred during the twelve month period that covers the filing year. The EP Dept. reviews the data requirements necessary to perform a ProdCost computer run for that twelve month period. When the EP Dept. is satisfied that the data represents the most reliable prediction of the expected conditions, it performs the computer analysis necessary to develop the total fuel and interchange expenses using the ProdCost program.

Q. What are the data requirements for use with the ProdCost program?

A. The ProdCost program requires data for the entire Pennsylvania-New Jersey-Maryland Interconnection (PJM) that will permit the program to simulate the economic dispatching philosophy of PJM for the entire period under study. This includes the following items for all PJM Companies:

- Unit Performance
- Projected Maintenance Schedules
- Forced Outage Rates
- Anticipated Hydro Output for Run-of-River and Storage Plants
- Capacity Additions and Retirements
- Energy Requirements

- Fuel Costs and Projected Escalation Rates for the Various Types of Fuel
- Two Party Purchase Agreements

Q. Would you please explain the "economic dispatching philosophy of the PJM".

A. The members of PJM operate as a single cost area with free flowing interconnection ties. This means that PJM schedules all available equipment of all member companies in such a manner as to meet the collective customer load of all companies at the lowest cost, regardless of ownership of the generating units that must be operated to meet that load. Because there are free flowing interconnection ties, all transmission of the combined member companies can be used to transport the energy from one member's generating source to another member's customer load without penalty, as long as the transmission system is operated within its reliability constraints.

Operating under this philosophy insures that the collective load will be satisfied at the minimum fuel cost. The contract among PJM members contains very rigid accounting rules to determine how the companies that generate power to meet customer load of other members are to be reimbursed for the expenses they incur. These rules are used to determine the costs incurred and the amount to be paid for interchange deliveries.

Q. Would you please explain how PECO collects the data mentioned above for both the PECO units and all the units of the other members of PJM.

A. Within the PJM organization, a ProdCost Task Force (PCTF), composed of representatives of all the member companies and reporting to the PJM Operating Committee, is charged with obtaining and keeping up to date the necessary information required from their respective companies in order to perform production cost analyses for PJM.

The Task Force is charged with providing a complete review of their input data every three months, and updates are supplied to all companies when appropriate. PECO's representative on the PCTF is responsible for updating the PJM data deck and, therefore, receives that data from the other companies in advance of the completion of the official update. Because PECO's representative shares this PJM responsibility with the responsibility assigned to him as a member of Philadelphia Electric Company's Electric Production Department to maintain PECO's updated ProdCost data deck, he is in frequent communication with his counterparts on the PCTF and obtains, on an expedited on-going basis any changes in other member companies' data.

PECO-specific data are assembled either by direct communication within the EP Dept. or through correspondence from other departments on a formal basis. Whenever the other departments review and change their forecasts that affect the projections of fuel and interchange, the EP Dept. is notified of these changes. Within the EP Dept., the reviews necessary to maintain updated data are performed on a rigid schedule. For instance, every month the maintenance outage schedule for the next twelve months is reviewed and changes made to reflect the present and expected conditions. This revised schedule is then submitted to the group responsible to the EP Dept. Management for monthly updates of the fuel and interchange expense projections.

Q. Mr. Carroll, how does PECO verify that the data used in its ProdCost program are correct?

A. The group responsible for the ProdCost program within the EP Dept. prepares a PJM Total Fuel and Interchange Projection, using the raw data as submitted. Then the results of this projection are compared with the historical values of generation by class. This comparison is made because often the raw data reflect historic averages which may or may not include unusually long forced outages on a particular unit, such as, for example, the extended forced outage of Eddystone 1, for replacement of main steam piping. It is often appropriate, in projecting future fuel and interchange expense, to make adjustments to the historic data for a unit to eliminate the unusual effects of such an outage.

As the next step in the process, PECO makes appropriate adjustments to reflect a reasonable output/availability for the various classes of generation, in conformity with the historical levels, after consideration of capacity additions, retirements and load requirements. This procedure provides a verification of the input data with respect to availability. Inputs with respect to heat rates, incremental maintenance, incremental fuel and the like are verified by manual calculations and, finally, by an examination of the loading order of the PJM units as they relate to one another. If a unit changes its order of loading by a significant amount, then the input is reexamined and verified to insure that the change is justified. PECO can then use the data submitted with a high degree of confidence that the results of the ProdCost run will reflect expected conditions on the PJM interconnection.

Q. Previously, you indicated that a monthly update of PECO's maintenance schedule is prepared. Would you please explain the process used by the Company to prepare the projected maintenance schedule.

A. The starting point for preparing a projected maintenance schedule is the overall preventive maintenance schedule for the boilers, turbines and reactors operated by the Company. This overall schedule incorporates the timing of major turbine inspections, major boiler inspections, refueling and end-of-cycle outages for reactors, and minor inspections of boilers and turbines in the years when no major inspections are scheduled. It also recognizes modifications and capital improvements that will be performed in conjunction with unit outages. Based on this overall schedule, the generating stations supply a description of the work projects that will be performed during the outages assigned to them for the future period. In addition, the Engineering and Research Department requests the time requirements necessary to perform their modifications and capital improvements.

The stations' work projects are then converted into outage days in conjunction with the Maintenance Division of the EP Dept., which must concur in the final estimate. The additional days required to perform operating and construction work prior to the start of, and after completion of, the maintenance work are then added to the outage days required for maintenance tasks. This process establishes the estimated outage durations required for each unit to meet the overall preventive maintenance program scheduled for the period under investigation.

The Electric Production Department's outage scheduling group then examines each unit's outage duration and schedules these outages for discrete time periods, giving considerations to the following:

1 - System reliability including coordination with outages of the transmission system

2 - System load requirements

3 - System economics

4 - Flows on the Susquehanna River

5 - Nuclear fuel burn-up considerations

6 - Station restrictions on simultaneous outages

7 - Overall Maintenance Division manpower constraints

The end result of this process is a projected system-wide outage schedule. The outage schedule is reviewed monthly and appropriate adjustments are made to reflect changes in work scope since the last review, changes in assigned time due to revised operating input, and any other factors that would necessitate a change in outage duration or timing.

Q. Mr. Carroll, you mentioned the fact that energy requirements, fuel price escalation rates, capacity additions and retirements and two-party purchase agreements are required inputs. How do you determine these inputs?

A. The energy requirements are received from Commercial Operations and are the Company's official projection of sales and associated energy output projections. The fuel price escalation rates are received from Fuel Procurement. The capacity additions and retirements are as provided by the System Planning Division and include the addition of Limerick No. 1 unit and the retirement of Southwark No. 1 and No. 2 units and the selected combustion turbines. The level of two-party purchase agreements is projected at the maximum two-party power available to the PJM due to transmission limitation considerations and PECO receives its allocated share according to the PJM allocation among the member companies. At present, this represents approximately 3000 mw to PJM and 430 mw to PECO.

Q. Mr. Carroll, turning to the final topic of your testimony, have you prepared certain sensitivity analyses to determine the impact of limitations on energy availability and fuel prices on PECO's total fuel and interchange expenses?

A. Yes, these analyses were performed under my direction.

Q. Would you explain how you determined the inputs used in these analyses.

A. There were five areas of energy availability and cost examined which could have a major impact on PECO's total fuel and interchange expenses: (1) a reduction in hydro energy due to low natural water flow as the result of limited precipitation; (2) a reduction in nuclear generation on PJM; (3) a reduction in coal generation energy available to PJM; (4) reduced two-party purchases of Western coal energy; and (5) an increase in fossil fuel prices.

For the reduction in hydro energy, I examined the output from Conowingo dam for its entire history when 11 units were operating at this station. The annual output ranged from 1,117,223 MWH as a low to 2,275,193 MWH as a high with the average at 1,732,000 MWH which is our predicted value for the revised ECR. This information is tabulated on Schedule 2(a) to my testimony. A value of 1,224,000 was then selected as a possible low value for use in the Prod Cost program. Since Conowingo shares the same water with Holtwood and Safe Harbor, all three plants were reduced in output to the same percentage level of their normal value. As you will note in Schedule 2(a), this value is not the lowest historic output, but is very close to the second lowest year on record.

The second condition examined was nuclear generation. Again, history was used as a guide to a possible low. Schedule 2(b) shows the Nuclear Generation Capacity Factor experienced on PJM. These historical values do not reflect TMI experience beyond 1978. A value of 49.9% was selected as a potential low nuclear output that could be repeated for all PJM units during the year, which is again not the lowest value experienced but is very close to the second lowest value.

The coal generation availability was reduced to reflect two separate conditions. First, if the Western coal generation available for two-party transactions was drastically reduced, it would have a significant impact on the entire PJM operating fuel expenses and on PECO's fuel and interchange expenses in particular. A joint study of East Central Area Reliability Coordination (ECAR) and Mid Atlantic Area Coordination (MAAC) has shown that the energy available from ECAR for MAAC is expected to start being reduced in the second half of the 1980's and by the early 1990's would be down to approximately 500 mw.

What PECO evaluated was, is there any possibility that this could happen in the near future and what would be the consequences? Upon review, it was felt that several conditions could accelerate this reduction in Western coal generation available to MAAC, as follows:

1 - Loss of one or more major generating units in the west for an extended period.

2 - Unexpected economic recovery in the ECAR region with its resultant energy requirements.

3 - A combination of these two.

4 - Either environmental or regional regulations that would limit the operation of coal fired capacity for energy needs outside the State or Region.

If these conditions did result in the reduction of reserve capacity in the West, it was felt that there was still a strong possibility that there would be a sharing of the operating reserve energy and, therefore, the Western coal fired energy for two-party transactions was reduced to 1,000 mw per hour with a 20% Forced Outage Rate applied.

The second part of the reduced coal energy availability was a consideration of the loss of generation from Eddystone Station, equivalent to one unit year combined with the remaining coal units on PJM remaining at their historical collective capacity factor. This condition was experienced in the past and it could possibly happen in the future as the result of a problem with the SO_2 removal system, MgO regeneration plants or EPA regulations.

Q. Mr. Carroll, you also mentioned the impact of fuel prices in your sensitivity analysis, what were the changes made to the fuel prices and what was the basis for these changes?

A. We examined the changes in fuel prices experienced in the past and found that during the 1973 to 1975 period and again in the 1979 to 1981 period, dramatic increases in fuel prices were experienced due to international market conditions. During these periods, oil and coal prices increased significantly as shown on Schedule 2(c). We looked at the annual rate of increase as if it was evenly spread over the three years (a less stringent rate of increase than was actually experienced) and applied this rate of inflation over the first year the new ECR will be in effect. Specifically, an escalation rate of 30% was applied to oil, somewhat less than the values shown on Schedule 2(c), and 11.7% to coal.

Q. Mr. Carroll, please continue with your description of how these five possible adverse conditions discussed above could affect PECO's total fuel and interchange expenses.

A. Two separate sensitivity scenarios employing these adverse conditions were analyzed. The Reduced Two Party Purchases and Higher Fuel Prices were included in both analyses. The analysis referred to as the Nuclear Generation Scenario also had low PJM Nuclear Energy and this reduced nuclear output was applied to all the presently commercially operating units on PJM. The analysis referred to as the Coal Generation Scenario combined the two common conditions (Reduced Two Party and High Fuel Prices) with Low Hydro Energy and Low PJM Coal Availability.

Q. What was the impact on PECO's total fuel and interchange expenses as a result of the combination of adverse conditions which you analyzed?

A. If the conditions represented by the Nuclear Generation Scenario were experienced during the first year the ECR is in effect, PECO's total fuel and interchange expenses would increase by $129.5 million or approximately 29%. If the conditions represented by the Coal Generation Scenario were experienced during the first year the new ECR will be in effect, PECO's total fuel and interchange expenses would increase by $108.9 million or approximately 24%. Moreover, the impact of these scenarios increases over time as the absolute magnitude of energy costs increases. Specifically, the impact of the Nuclear Generation Scenario is $141.3 million in year 2 and $232.2 million in year 3. Similarly, the impact of the Coal Generation Scenario is $137.4 million in year 2 and $136.8 million in year 3.

Q. Is PECO predicting that any of the conditions used in either the Nuclear Generation or Coal Generation Scenarios will actually happen in the first new ECR year?

A. No, PECO is not predicting that any of the unusual conditions inputted to the Nuclear Generation or Coal Generation Scenarios will actually happen; rather, PECO is predicting the conditions of Fuel Cost, Hydro Generation, Nuclear Unit Availability and Coal Unit Availability as shown in Exhibit JJC-1, Item 3(i). However, if adverse circumstances were to be encountered with respect to either or each of these natural, international and regulatory conditions which impact unit operation, but which are beyond PECO's control, one of the analyzed Scenarios could well be experienced during the analysis period. Again, I should emphasize that each of these adverse conditions and the combinations which I have presented are very real possibilities based on current conditions and in light of historic experience.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

WESTINGHOUSE UNIT CAPACITY FACTORS (MDC)

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	AVG.	WT.AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	77.3	16.1	66.5	74.9	81.8	5	63.3	316.6
SURRY 1	PWR	WE	WE	775	788	12	72	36.3	35.0	80.8	51.8	49.0	5	50.6	252.9
SURRY 2	PWR	WE	WE	775	788	5	73	32.9	75.9	80.9	60.2	76.5	5	65.3	326.4
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	67.9	79.6	67.9	51.5	52.6	5	63.9	319.5
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	56.7	40.7	58.8	78.3	38.4	5	54.6	272.9
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	36.2	35.9	18.4	0.7	71.3	5	32.5	162.5
SALEM 1	PWR	WE	WE	1079	1090	6	77	60.0	65.5	43.3	56.9	22.4	5	49.6	248.1
SALEM 2	PWR	WE	WE	1106	1115	10	81			82.0	7.7	32.9	3	40.9	122.6
WESTINGHOUSE AVERAGES								52.5	49.8	62.3	47.8	53.1	38		53.2

OVERALL AVG. 53.2
SALEM AVG. 46.3
AVG. W/O SALEM 55.0

20-Dec-85

GENERAL ELECTRIC BWR CAPACITY FACTORS (MDC)

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	AVG.	WT.AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	67.6	50.4	75.8	50.2	65.8	5	62.0	309.8
DRESDEN 3	BWR3	GE	GE	773	794	11	71	63.8	76.5	57.4	61.3	31.0	5	58.0	290.0
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	51.0	85.0	48.2	85.7	49.6	5	63.9	319.5
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	53.5	55.9	75.1	46.8	73.8	5	61.0	305.1
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	64.8	47.2	84.5	23.3	83.9	5	60.7	303.7
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	60.1	80.1	47.7	68.4	43.2	5	59.9	299.5
FITZPATRICK	BWR4	GE	GE	810	821	7	75	60.1	67.4	69.9	65.3	68.9	5	66.3	331.6
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	26.9	47.5	27.6	56.9	20.1	5	35.8	179.0
HATCH 1	BWR4	GE	GE	752	777	12	75	71.4	41.6	43.3	59.2	54.5	5	54.0	270.0
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	74.1	67.1	52.4	57.8	3.1	5	50.9	254.5
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	56.8	36.9	42.2	20.1	72.5	5	45.7	228.5
HATCH 2	BWR4	GE	GE	748	784	9	79	53.7	66.2	55.2	56.4	28.5	5	52.0	260.0
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	47.1	72.0	52.1	48.3	26.3	5	49.2	245.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	79.6	34.5	94.1	26.7	81.9	5	63.4	316.8
G. E. BWR AVERAGES								58.7	60.2	56.6	54.3	49.6	60		55.9

OVERALL AVG. 55.91
PEACH BOTM AVG 56.26
AVG. W/O P.BTM 55.85

UNIT AVAILABILITY FACTORS 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	77.6	15.8	64.1	73.3	82.6	5	62.7
SURRY 1	PWR	WE	WE	775	788	12	72	44.9	38.9	88.8	57.2	58.5	5	57.7
SURRY 2	PWR	WE	WE	775	788	5	73	35.8	79.6	88.3	65.4	83.5	5	70.5
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	69.5	77.7	66.3	52.2	54.4	5	64.0
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	64.8	46.0	65.4	84.0	51.9	5	62.4
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	53.2	59.8	22.5	2.6	76.3	5	42.9
SALEM 1	PWR	WE	WE	1079	1090	6	77	69.2	78.1	47.9	58.6	27.1	5	56.2
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A.	94.6	97.3	12.3	36.4	4	60.2
													39	
YEARLY AVERAGES								59.3	61.3	67.6	50.7	58.8		

****

OVERALL AVG.	59.55
SALEM AVG.	57.94
AVG. W/O SALEM	60.03

****

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	93.3	60.1	92.4	58.0	72.9	5	75.3
DRESDEN 3	BWR3	GE	GE	773	794	11	71	71.8	94.3	63.5	73.1	37.7	5	68.1
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	66.5	94.1	68.0	94.3	53.4	5	75.3
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	62.5	68.0	83.9	64.2	77.9	5	71.3
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	72.6	50.7	91.0	26.5	90.3	5	66.2
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	69.2	85.1	54.5	74.4	66.5	5	69.9
FITZPATRICK	BWR4	GE	GE	810	821	7	75	70.2	74.7	75.0	70.6	76.8	5	73.5
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	35.2	66.3	38.6	64.3	25.5	5	46.0
HATCH 1	BWR4	GE	GE	752	777	12	75	81.7	50.1	49.3	71.3	62.3	5	62.9
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	79.1	72.6	57.3	61.9	5.9	5	55.4
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	68.9	47.5	62.0	24.2	77.4	5	56.0
HATCH 2	BWR4	GE	GE	748	784	9	79	60.0	78.5	63.8	65.9	32.3	5	60.1
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	51.6	79.3	58.1	50.9	29.0	5	53.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	80.7	36.6	95.6	31.0	85.9	5	66.0
													70	
YEARLY AVERAGES								68.8	68.4	68.1	59.3	56.7		

****

OVERALL AVG.	64.27
PEACH BOTM AVG	59.87
AVG. W/O P.BTM	65.00

****

FORCED OUTAGE HOURS 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	N.A	1523.2	724.9	131.0	958.5	4	834.4
SURRY 1	PWR	WE	WE	775	788	12	72	N.A	458.0	323.3	223.2	222.0	4	306.8
SURRY 2	PWR	WE	WE	775	788	5	73	N.A	65.7	193.8	102.3	1087.3	4	362.3
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	N.A	248.0	778.6	552.3	1496.3	4	768.8
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	N.A	992.7	454.1	381.9	792.4	4	655.3
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	N.A	3065.3	45.6	4715.5	870.3	4	2174.2
SALEM 1	PWR	WE	WE	1079	1090	6	77	N.A	1915.9	308.0	3630.0	3851.7	4	2426.4
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A	103.3	240.5	3839.3	5589.2	4	2443.1
													32	
YEARLY AVERAGES								N.A	1046.6	383.6	1696.9	1858.5		

****
OVERALL AVG. 1246.40
SALEM AVG. 2434.74
AVG. W/O SALEM 850.29
****

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	YRS	AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	N.A	430.3	556.0	1075.5	289.8	4	587.9
DRESDEN 3	BWR3	GE	GE	773	794	11	71	N.A	438.8	268.9	144.5	547.5	4	349.9
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	N.A	181.6	115.1	114.5	127.8	4	134.8
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	N.A	66.4	1257.4	28.2	436.6	4	447.2
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	N.A	168.3	737.5	204.0	820.0	4	482.5
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	N.A	799.5	280.3	368.1	249.4	4	424.3
FITZPATRICK	BWR4	GE	GE	810	821	7	75	N.A	732.5	556.5	335.4	323.3	4	486.9
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	N.A	2607.1	1477.9	946.9	544.8	4	1394.2
HATCH 1	BWR4	GE	GE	752	777	12	75	N.A	649.1	1520.6	375.3	967.7	4	878.2
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	N.A	487.9	1300.3	558.0	863.0	4	802.3
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	N.A	1194.6	2625.0	138.8	632.2	4	1147.7
HATCH 2	BWR4	GE	GE	748	784	9	79	N.A	589.7	726.0	1169.9	238.6	4	681.1
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	N.A	1616.0	165.4	3427.3	116.4	4	1331.3
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	N.A	444.4	386.0	141.3	764.2	4	434.0
YEARLY AVERAGES								N.A	743.30	855.21	644.84	494.38	56	

****
OVERALL AVG. 684.43
PEACH BOTH AVG 882.63
AVG. W/O P.BTH 651.40
****

UNIT FORCED OUTAGE RATES 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	1.5	52.4	11.4	2.0	11.7	5	15.8
SURRY 1	PWR	WE	WE	775	788	12	72	39.1	11.9	4.0	4.3	4.1	5	12.7
SURRY 2	PWR	WE	WE	775	788	5	73	3.1	0.9	2.4	1.8	12.9	5	4.2
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	0.3	3.5	11.8	10.8	23.8	5	10.0
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	15.3	19.8	7.3	4.9	14.8	5	12.4
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	24.1	36.9	2.3	95.4	11.5	5	34.0
SALEM 1	PWR	WE	WE	1079	1090	6	77	5.6	21.9	6.8	41.4	61.8	5	27.5
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A.	5.4	2.7	78.0	63.6	4	37.4
													39	
YEARLY AVERAGES								12.7	19.1	6.1	29.8	25.5		

****

OVERALL AVG.	18.80
SALEM AVG.	31.91
AVG. W/O SALEM	14.87

****

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	4.4	7.6	6.4	17.5	4.3	5	8.0
DRESDEN 3	BWR3	GE	GE	773	794	11	71	2.5	5.0	4.6	2.2	14.2	5	5.7
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	4.2	2.2	1.9	1.4	2.7	5	2.5
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	8.3	1.1	14.6	0.5	6.0	5	6.1
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	7.5	3.7	8.5	8.1	9.4	5	7.4
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	10.8	9.7	5.5	5.3	4.1	5	7.1
FITZPATRICK	BWR4	GE	GE	810	821	7	75	4.0	10.1	7.8	5.1	4.6	5	6.3
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	16.1	31.0	30.4	14.4	19.6	5	22.3
HATCH 1	BWR4	GE	GE	752	777	12	75	18.1	12.9	26.1	5.7	15.0	5	15.6
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	11.7	7.1	20.6	9.3	63.1	5	22.4
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	8.2	22.3	32.6	6.1	8.5	5	15.5
HATCH 2	BWR4	GE	GE	748	784	9	79	12.4	7.9	11.5	16.8	7.8	5	11.3
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	4.0	18.9	3.1	43.4	4.4	5	14.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	11.0	12.2	4.4	4.9	9.2	5	8.3
													70	
YEARLY AVERAGES								8.8	10.8	12.7	13.2	12.4		

****

OVERALL AVG.	10.95
PEACH BOTM AVG	11.55
AVG. W/O P.BTM	10.85

****

Conowingo Annual Output

MWH

Year	MWH Output
1965	1,117,223
1966	1,303,458
1967	1,894,731
1968	1,585,765
1969	1,342,128
1970	1,876,803
1971	1,737,834
1972	2,242,533
1973	2,131,912
1974	1,937,729
1975	2,275,193
1976	2,065,359
1977	1,996,723
1978	1,700,078
1979	2,154,921
1980	1,239,494
1981	1,396,799
1982	1,581,431
1983	1,738,785
1984	2,084,881

PJM Nuclear Unit Combined Capacity Factor

Year	% Capacity Factor	No. of Units
1970	74.4	1
1971	77.5	1
1972	80.0	1
1973	64.0	1
1974	67.6	1
1975	66.3	5
1976	69.3	5
1977	59.8	7
1978	69.1	7
1979	58.6	7
1980	63.4	7
1981	63.3	7
1982	65.9	7
1983	46.9	8
1984	49.8	8

Fuel Sensitivity Analysis
Historical Data

Coal

1973 through 1975

	Eddystone	Cromby
11-20-72	53.19	51.23
12-22-75	126.49	137.97
Ratio	2.378	2.693
Approx. Wt. Avg.	2.441	
Equiv. Annual Factor	1.346	

1978 through 1980

	Eddystone	Cromby
11-30-77	117.81	129.10
12-12-80	166.03	169.42
	1.4093	1.3123
		1.3899
		1.116

Oil #6

Loc.	11-20-72	12-22-75	Ratio	11-23-77	12-12-80	Ratio
Schuyl.	75.37	203.99	2.707	221.78	543.47	2.45
Cromby	79.34	203.85	2.569	228.95	538.19	2.351
Chester	73.54	199.63	2.715	222.46	548.43	2.465
Delaware	73.54	199.63	2.715	222.46	548.43	2.465
Richmond	73.54	199.63	2.715	222.46	548.43	2.465
Barbadoes	79.18	209.77	2.65	-	-	-
Southwrk.	73.54	199.63	2.715	222.46	548.43	2.465
Eddystone	-	-	-	222.46	548.43	2.465
Approx. Wt. Avg.			2.68			2.447
Equiv. Annual Factor			1.39			1.347

Harrisburg
R-850152

Education Background, Business Experience and Qualifications
of
A. Gerald Harris

I was awarded a degree of Bachelor of Science in Economics from Howard University (Washington, D.C.) in 1964. Since that time I have completed course work toward a Masters Degree in Economics at the Maxwell School of Syracuse University. In addition, over the years I have attended numerous professional and business seminars and classes.

In 1965, I joined Niagara Mohawk Power Corporation in Syracuse, New York as a market research analyst. I advanced from market research analyst to the position of financial analyst and later to corporate planner. As a corporate planner I was responsible for the utilities rate and revenue planning activities. I prepared studies relating to utility rate matters including cost of service and rate design. I was also responsible for the preparation of energy and demand forecasts.

In September, 1978, I joined Associated Utility Services, Inc. as assistant vice president. In January, 1980, I was elevated to the position of vice president. Since joining Associated Utility Services, Inc., I have been responsible for the firm's computer-based research activities as head of the economics research department. In this capacity I coordinate the firm's econometric modeling, financial analysis, and statistical analysis activities. In addition, my duties include assisting utility organizations and regulatory agencies in the areas of cost of service and rate design applications as well as other financial, economic and regulatory matters. I have supervised the preparation of cost of service and rate design studies which were employed in connection with the testimony presented by myself and other members of our firm before regulatory agencies. I have presented direct testimony on the subject of cost of service, rate design, statistical analysis and rate of return differential.

My studies, in the form of prepared direct testimony, have been presented before the Federal Energy Regulatory Commission, Federal Maritime Commission, Interstate Commerce Commission, and eleven State Commissions consisting of:

Arkansas	Ohio
Delaware	Pennsylvania
Indiana	Rhode Island
Massachusetts	Texas
Michigan	Washington
New York	

My testimony has been offered on behalf of municipal and investor-owned public utilities and the staff of regulatory commissions. I have also sponsored testimony before the New Jersey Board of Public Utilities on behalf of Browning-Ferris Inc., of Elizabeth and New Jersey Natural Gas Company.

The following tabulation provides a listing of the cases in which I have sponsored testimony.

Alpena Power Company	Docket No. U-7050
Arkansas Power & Light Company	Docket No. U-3108
Browning-Ferris, Inc. of Elizabeth, NJ	Docket No. 8506-643
Collier County, Florida	
Delaware Public Service Commission re: Delaware Electric Cooperative	Docket No. 4679
Delaware Public Service Commission re: Delmarva Power & Light Company	Docket Nos. 923 - Phase II and 81-12
Duquesne Light Company	Docket No. R-80011069
Indiana & Michigan (FERC)	Docket No. ER-78-379
National Fuel Gas Company	Docket No. R-832469
New Jersey Natural Gas Company	Docket No. GR8510974
Niagara Mohawk Power Corporation	Docket No. N/A
Northern Indiana Fuel & Light Company	Cause No. 37204

Ohio Edison Company	Docket No. N/A
Pennsylvania Gas & Water Company	Docket No. R-832475 and R-832315
Pennsylvania Power & Light Co.	Docket No. R-80031114
Pennsylvania Power Company	Docket Nos. R-79121020, R-811510, R-821918, R-832409, and R-842-740
Pennsylvania Power Company (FERC)	Docket No. ER-81-779-000
Providence Gas Company	Docket No. 1741
Puerto Rico Manufacturers Assoc. & Gov't. of U.S. Virgin Islands	Docket No. 81-10
Texas-New Mexico Power Company (formerly Community Public Service Co.)	Docket No. 3320
Washington Water Power Company	Cause No. U-83-26
West Penn Power Company	Docket No. R-80021082
Western Massachusetts Electric Co.	Docket No. DPU-1300

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452).

In addition to clients for whom I have presented testimony before regulatory bodies, I have provided primary utility consulting services to:

Atlantic City Electric Company
The Borough of Butler, NJ
The Borough of Park Ridge, NJ
The City Council of New Orleans, LA
Consolidated Gas Transmission Corporation
The District of Columbia Public Service Commission
The East Ohio Gas Company
Florida Power & Light Company
Ohio Power Company
Nantahala Power & Light Company
Southwest Gas Corporation
Vermont Electric Power Company

I have also performed various services for numerous other utilities. Non-utility clients whom I have served are Parsons Brinckerhoff Development Group, the Puerto Rico Manufacturers Association, and the Government of the U.S. Virgin Islands.

I am a member of the American Economics Association, The National Association of Business Economists, The Pennsylvania Gas Association, and The Middle West Gas Association.

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R-850152 Hbg
1/28/86 JK

PHILADELPHIA ELECTRIC COMPANY

Exhibit to Accompany
the Supplemental Direct Testimony

of

Joseph F. Brennan, President
Associated Utility Services, Inc.

Concerning

Energy Cost Rate

DOCKETED
JAN 30 1986

PHILADELPHIA ELECTRIC COMPANY
ESTIMATED IMPACT ON NET INCOME ASSUMING ONLY 80% OF FUEL COSTS ARE SUBJECT TO RECOVERY THROUGH THE ENERGY COST RATE (ECR)

SCENARIO(S)	INCREASE IN FUEL AND INTER-CHANGE COSTS (1) (A)	IMPACT ON BEFORE INCOME TAX INCOME (2) (B)	INCOME TAX AT ASSUMED 50% RATE (C)	IMPACT ON NET INCOME (DECREASE) (COL B - C) (D)	COMMON EQUITY AT 12-31 (3) (E)	DECREASE IN RATE OF RETURN ON AVERAGE COMMON EQUITY (COL D÷COL E) (F)
JUNE 30,1987						
COAL SCENARIO	$108904230	$21780846	$10890423	$10890423	$3420000000	0.32%
NUCLEAR SCENARIO	129438261	25887652	12943826	12943826	3420000000	0.38
JUNE 30,1988						
COAL SCENARIO	$137436473	$27487295	$13743647	$13743647	$3585000000	0.38
NUCLEAR SCENARIO	141349722	28269944	14134972	14134972	3585000000	0.39
JUNE 30,1989						
COAL SCENARIO	$136827857	$27365571	$13682786	$13682786	$3753000000	0.36
NUCLEAR SCENARIO	232231163	46446233	23223116	23223116	3753000000	0.62

NOTES:
(1) COMPANY PROVIDED
(2) 20% OF COLUMN A
(3) DECEMBER 31 IS THE MIDPOINT OF THE TWELVE MONTHS ENDED JUNE 30. THE ESTIMATE OF COMMON EQUITY AT YEARS-END 1986-1988 ARE DEVELOPED ON SCHEDULE 1, PAGE 2.

SCENARIOS DEFINED:
COAL SCENARIO - LOW RIVER HYDRO OUTPUT, FUEL PRICE INCREASE IN 1st YEAR, TWO PARTY PURCHASES LIMITED TO 1,000 MW, AND PJM COAL CAPACITY FACTOR LIMITED TO 62.2%.
NUCLEAR SCENARIO - FUEL PRICE INCREASE IN 1st YEAR, TWO PARTY PURCHASES LIMITED TO 1,000 MW, AND NUCLEAR GENERATION ON PJM REDUCED TO 49.9%.

PHILADELPHIA ELECTRIC COMPANY
DEVELOPMENT OF
ESTIMATED COMMON EQUITY
AT 12-31-85 TO 12-31-88, INCLUSIVE

	(MILLIONS)
TOTAL COMMON EQUITY AT 12-31-84(1)	$2891
+ COMMON STOCK ISSUANCES(2)	211
+EARNINGS RETAINED(3)	100
TOTAL COMMON EQUITY AT 12-31-85	3202
+ COMMON STOCK ISSUANCES(2)	168
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-86	3420
+ COMMON STOCK ISSUANCES(2)	115
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-87	3585
+ COMMON STOCK ISSUANCES(2)	118
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-88	$3753

NOTES: (1) COMPANY'S FILING, ATTACHMENT III-A-2
(2) COMPANY'S FILING, ATTACHMENT III-F-2
(3) SUPPORTING DATA FOR III-F-2, PROVIDED BY COMPANY

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage Including and Excluding All AFC and Assuming AFC Related to Limerick 1 Becomes Cash Earnings

Type of Capital	Approximate Ratios (1)	Rate	After Income Tax Weighted Rate	Before Income Tax Weighted Rate (2)
Including All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	15.43 (4)	5.86	11.72
	100%		12.44%	19.46%
Before income tax interest coverage (19.46% ÷ 5.42%)				3.6x
Excluding All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	1.19 (5)	0.45	0.90
	100%		7.03%	8.64%
Before income tax interest coverage (8.64% ÷ 5.42%)				1.6x
Assuming AFC Related to Limerick 1 Becomes Cash Earnings				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	12.04 (6)	4.58	9.16
	100%		11.16%	16.90%
Before income tax interest coverage (16.90% ÷ 5.42%)				3.1x

See page 3 for notes.

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage
Including and Excluding All AFC and Assuming AFC related to Limerick 1 Becomes Cash Earnings
and After Reflecting Largest Decline in Return on Common Equity Due to 80/20 ECR

Type of Capital	Approximate Ratios (1)	Rate	After Income Tax Weighted Rate	Before Income Tax Weighted Rate (2)
Including All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	14.81 (7)	5.63	11.26
	100%		12.21%	19.00%
Before income tax interest coverage (19.00% ÷ 5.42%)				3.5x
Excluding All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	0.57 (8)	0.22	0.44
	100%		6.80%	8.18%
Before income tax interest coverage (8.18% ÷ 5.42%)				1.5x
Assuming AFC Related to Limerick 1 Becomes Cash Earnings				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	11.42 (9)	4.34	8.68
	100%		10.92%	16.42%
Before income tax interest coverage (16.42% ÷ 5.42%)				3.0x

See page 3 for notes.

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage
Including and Excluding All AFC and Assuming
AFC Related to Limerick 1 Becomes Cash Earnings

Notes:

(1) Approximate capital structure ratios at time rates for service in this proceeding will go into effect.

(2) Based on an assumed 50% income tax rate.

(3) Approximate long-term debt and preferred stock cost rate at June 30, 1986 updated to reflect known changes to Company's financing plan.

(4) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494,013 million ÷ $3,202 million = 15.43%).

(5) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) of $494.013 million minus total AFC of $455.850 million including $92.298 million included as other income as provided by the Company and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494.013 million $455.850 million = $38.163 million ÷ $3,202 million = 1.19%).

(6) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) of $494.013 million minus total AFC of $455.850 million plus $347.452 million of AFC related to Limerick 1 as provided by the Company and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494.013 million - $455.850 million + $347.452 million = $385.615 million ÷ $3,202 million = 12.04%).

(7) Developed by reducing the return rate on common equity calculation in Note (4) of 15.43% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (15.43% - 0.62% = 14.81%).

(8) Developed by reducing the return rate on common equity calculation in Note (5) of 1.19% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (1.19% - 0.62% = 0.57%).

(9) Developed by reducing the return rate on common equity calculation in Note (6) of 12.04% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (12.04% - 0.62% = 11.42%).

CreditComment

Electric utility benchmarks revised

S&P recently developed new, more conservative financial benchmarks for rating investor-owned electric utility bonds. In light of the increasing business and industry risks confronting electric utilities, more conservative financial profiles are necessary to maintain creditor protection.

The new benchmarks are not expected to result in substantial revisions of outstanding ratings since they do not signal a fundamental change in rating standards or methodologies. Rather, they serve to highlight the evolving risks in the electric utility business. As a practical matter, rating analyses have been incorporating more stringent financial standards for some time.

S&P's rating perspective involves a prospective look at a utility's financial performance. Estimates of future earnings, cash flow, and debt levels are matched against the benchmarks to help determine the financial protection that will be available for bondholders. Also, analyses will continue to encompass substantially more than comparisons of financial ratios with rating benchmarks. Where qualitative business or industry risk elements exist, such as unresponsive regulation, weak or highly cyclical service territory economies, uncertain construction, or high potential acid rain exposure, S&P will continue to look for a more conservative financial profile than indicated by the benchmarks for a particular rating category.

Business risk for electric utilities continues to increase. Sales growth is no longer assured. Annual usage increases of 8%–10%, once common in the past, are unlikely in the future. For some utilities, the likelihood of any usage increase is remote. Major customers are seeking alternatives to traditional utility service, some through cogeneration, some by trying to make their own deals with other utilities.

Service costs are increasing because of fuel costs, regulation, and inflated capital and construction costs. As those costs go up, utilities are finding themselves in double jeopardy. First, political regulators may be unwilling or unable to authorize rates sufficient to cover rising costs. Second, rates high enough to fully cover costs might price electric service beyond the ability or willingness of customers to pay. Utility plant investment has become a risky proposition. Regulators are becoming increasingly reluctant to recognize operating plant in service.

Utility investment is also becoming less economical and more unproductive. For example, acid rain remedies could cost billions of dollars to implement, and they will not generate more electricity, nor will they increase the efficiency of utility assets. Both regulators and common stock investors are likely to react unfavorably. In addition, the government's tax reform proposals seem designed with the specific intent of crippling smokestack industries, including electric utilities. All this translates into heightened risk for utility bondholders. The new financial benchmarks will more accurately relate the debt ratings to the risks.

New benchmarks
Electric utilities

	AAA	AA	A	BBB	BB
Pretax interest coverage (excl. AFDC*) (x)	Greater than 4.5	3.5–5.0	2.5–4.0	1.5–3.0	Less than 2.0
Net cash flow/permanent capital (%)	Greater than 10.0	7.0–11.0	5.0–8.0	2.5–6.0	Less than 3.0
Debt leverage (%)	Less than 41	39–46	44–52	50–58	Greater than 56

*Also excludes other noncash accruals.

Obsolete benchmarks—superseded Jan. 28, 1985
Electric utilities

	AAA	AA	A	BBB
Pretax interest coverage (incl. AFDC) (x)	Greater than 4.0	3.25–4.25	2.50–3.50	Less than 3.0
Net cash flow/cash construction (%)	(None published)	Greater than 40	20–50	Less than 30
Debt leverage (%)	Less than 45	42–47	45–55	Greater than 53

Debt leverage

Debt leverage benchmarks were shaved by several hundred basis points across the board. The most readily available response to increasing industry and business risk is a less leveraged capital structure. A solid 'AA' capital structure would have debt leverage sustainable at about 40% of capital, less than 10% preferred stock, and common equity of 50% or more.

The net cash flow-to-total capital ratio will be used to determine the adequacy of cash flow. The former benchmarks related cash flow to construction expenditures. But construction is not a very stable series, especially when base load generation

S&P electric utility financial benchmark ratio definitions

Pretax interest coverage: The sum of net income, gross interest charges, and income taxes divided by gross interest charges. For coverages excluding AFDC, deduct total AFDC (debt and equity components) from the numerator.

Debt leverage: The sum of long-term debt, current maturities and short-term borrowings used for bridge financing, divided by permanent capital. Numerator and denominator include off balance sheet obligations.

Permanent capital: The sum of long-term debt, current maturities, short-term borrowings used for bridge financing, off balance sheet obligations, and all stockholders' equity.

Gross cash flow: The sum of net income, depreciation, depletion, amortization, net deferred income taxes, and net investment tax credits, less total AFDC.

Net cash flow: Gross cash flow, less preferred, preference, and common dividends.

Cash construction: Gross construction capitalized, less total AFDC.

is involved. The ratio tends to be volatile, and it does not adequately depict either stability or sufficiency of utility cash flow. Cash flow-to-capital is a preferable alternative. Net cash flow-to-capital of 10%—a 10-year turnover of the investment base—is achievable with good earnings performance, realistic depreciation, and conservative tax and accounting policies. This level of cash generation is appropriate for a solid 'AA' senior debt rating. However, S&P will continue to analyze construction expenditures. When they are heavy, S&P will look for sufficient cash flow to fund the program without creating undue external financing stress.

The biggest difference from previously published benchmarks flows from the income statement. The allowance for funds used during construction (AFDC) can no longer be considered as a source of genuine earnings protection. As the portion of AFDC climbed in recent years, analytical confidence in the quality of the assets created by AFDC accruals has gone down sharply.

AFDC represents more than half of industry earnings. The result is a real return on investment that is completely uncompetitive with capital market-driven rates, and common dividends that are paid out of illusory profits.

The new electric utility benchmarks are more stringent to reflect the evolving risks in the electric utility business. The industry's risk in 1985 is not compatible with the average 'AA' debt rating it enjoyed in 1970. The new benchmarks demonstrate that utilities need stronger financial profiles to achieve and sustain strong ratings than in the past.

Douglas Randall

Railroad acquisition activity rolls ahead

Recent events suggest further consolidation of the railroad industry. Norfolk Southern Corp. was selected by the Department of Transportation (DOT) to acquire Consolidated Rail Corp. (Conrail). A federal bankruptcy court in Chicago ruled in favor of Soo Line Railroad Co.'s bid to acquire the core assets of the Milwaukee Road, formally known as the Chicago, Milwaukee, St. Paul & Pacific Railroad Co. Katy Industries announced that it was negotiating with a buyer for its Missouri-Kansas-Texas Railroad subsidiary.

S&P views the probable credit effect of these events as neutral for Norfolk Southern's railroad subsidiaries, negative for the Soo Line, and positive for the Missouri-Kansas-Texas Railroad. Because the outcome of these transactions is uncertain and may not be finalized for a year or more, S&P will not take any rating action at this time.

Norfolk Southern Corp.

Norfolk Southern Corp., the holding company formed by the 1982 merger of the Norfolk & Western and the Southern railways, agreed to pay $1.2 billion for the government's 85% interest in Conrail and offered Conrail's employees $375 million for their 15% interest. The company also agreed last year, subject to Interstate Commerce Commission approval, to acquire North American Van Lines, the nation's fifth largest commercial trucking company, for $315 million. Norfolk Southern has no rated debt, however. S&P rates the subsidiary railroad's equipment trust certificates 'AAA' and mortgage bonds 'AA'.

Norfolk Southern's total debt to capital ratio of 17.6% on Dec. 31, 1984 included $961.2 million of debt and $4.5 billion of equity. Cash flow of $904.9 million covered 94% of its total debt while cash and short-term investments amounted to $1.0 billion. The exceptional financial strength of Norfolk Southern, which has no debt beyond that of the railroad operating companies, suggests a strong capacity to finance both acquisitions without any significant impairment of creditworthiness.

To complete the Conrail sale, Congressional approval is needed. S&P anticipates that this will entail lengthy hearings addressing shipper, labor, and other carrier concerns. Under the provisions of the 1981 Northeast Rail Services Act, which mandated the return of Conrail to the private sector, Interstate Commerce Commission approval of the sale is not needed. Norfolk Southern agreed to a number of conditions to keep Conrail healthy and preserve competition in the combined service territory. A Norfolk Southern-Conrail combination would create a 31,500-mile system serving 24 states east of the Mississippi.

Soo Line Railroad Co.

Soo Line Railroad Co.'s $57.1 million bid to acquire the core assets of the Milwaukee Road was selected over a competing $786 million offer made by the Chicago & Northwestern Transportation Co. (C&NW). In his decision in favor of the Soo, the judge stated that the Soo Line-Milwaukee combination would better preserve competition and jobs than would the C&NW-Milwaukee combination. S&P expects that Chicago Milwaukee Corp., parent of the Milwaukee Road, may challenge the court's selection of the lower Soo Line bid.

Financing of the acquisition could weaken the ratings of approximately $100 million of equipment and mortgage debt of Soo Line and its predecessor Wisconsin Central Railroad and Minneapolis St. Paul & Sault Ste. Marie Railway. The $57.1 million purchase price, consisting of cash and the assumption of Milwaukee Road obligations, would significantly alter Soo Line's capital structure, which included $107.5 million of debt and $274.9 million of equity at Sept. 30, 1984.

Soo Line, an upper-midwestern carrier that is 55.7% owned by Canadian Pacific Ltd., would nearly double its current size and gain access to the Kansas City and Louisville gateways with the addition of Milwaukee's 3,100-mile system. For the first nine months of 1984, the Milwaukee Road earned $14.6 million on revenues of $331.1 million while the Soo earned $14.0 million on revenues of $237 million.

Missouri-Kansas-Texas Railroad

Katy Industries announced that it is seeking a buyer for its 98%-owned Missouri-Kansas-Texas Railroad (M-K-T) subsidiary. While the buyer is unnamed, company announcements suggest that it is another railroad. The M-K-T is operating profitably now after experiencing losses for much of the last 30 years. The system extends from Kansas City to the Gulf of Mexico via Dallas, Fort Worth, and Houston and has about $250 million in annual revenue. Its mortgage bonds are rated 'B' and nonpaying income debentures 'C'. Consolidation with a larger system could enhance M-K-T's creditworthiness.

Marna P. Dann

Exhibit JFB-2
Schedule 3
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
INANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	21.6%	15.1%	15.7%	17.6%	14.1%	16.8%
MARKET/AVERAGE BOOK RATIO	69.9	88.4	84.7	69.3	75.1	77.5
DIVIDEND YIELD	17.6	13.4	13.5	14.9	12.7	14.4
APITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	52.4%	50.0%	51.1%	51.7%	51.2%	51.3%
PREFERRED STOCK	11.3	12.0	11.2	11.9	13.3	11.9
COMMON EQUITY	36.3	38.0	37.7	36.4	35.5	36.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	54.0%	51.9%	51.6%	52.1%	51.8%	52.3%
PREFERRED STOCK	10.9	11.5	11.0	11.8	13.1	11.7
COMMON EQUITY	35.1	36.6	37.4	36.1	35.1	36.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
ATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	15.0%	13.3%	13.2%	12.1%	10.6%	12.8%
OVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.4x	2.4x	2.4x	2.1x	2.1x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.1	2.0	1.9	2.0	2.0
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.7	1.7	1.6	1.6	1.7
OVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	1.6x	1.6x	1.7x	1.5x	1.5x	1.6x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.3	1.3	1.4	1.3	1.3	1.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.1	1.1	1.2	1.1	1.1	1.1
ALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	86.6	85.8	76.5	84.4	84.3	83.5
EFFECTIVE INCOME TAX RATE	20.9	22.4	28.2	19.3	16.4	21.4
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	5.2	8.9	11.5	2.8	3.6	6.4
COMMON DIVIDEND COVERAGE (5)	1.1x	1.2x	1.3x	1.1x	1.1x	1.2x

E PAGE 2 FOR NOTES.

Philadelphia Electric Company
Selected Risk Indices and Financial Ratios
1980-1984, Inclusive

Notes:

(1) Based upon financial statements as originally reported in each year.

(2) Coverages - including all AFC - represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety included as income, cover fixed charges.

(3) Coverages - excluding all AFC - represent the number of times available earnings, excluding all AFC, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(5) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

Source of Information: Associated Utility Services Computerized Data Base
Standard & Poor's Compustat Services, Inc. Utility Compustat II

GROUP OF FIVE ELECTRIC COMPANIES HAVING INCENTIVE FUEL CLAUSES
SELECTED RISK INDICES AND FINANCIAL RATIOS (6)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	16.3%	15.0%	17.7%	16.9%	13.4%	15.9%
MARKET/AVERAGE BOOK RATIO	96.3	100.4	85.7	76.2	74.5	86.6
DIVIDEND YIELD	10.9	10.2	11.6	12.5	11.9	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	48.1%	47.5%	46.2%	47.2%	47.5%	47.3%
PREFERRED STOCK	10.7	11.8	13.0	13.8	14.2	12.7
COMMON EQUITY	41.2	40.7	40.8	39.0	38.3	40.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	48.9%	48.8%	48.3%	50.6%	50.6%	49.4%
PREFERRED STOCK	10.5	11.5	12.5	12.9	13.3	12.2
COMMON EQUITY	40.6	39.7	39.2	36.5	36.1	38.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	15.3%	15.0%	15.1%	13.0%	10.0%	13.7%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.3x	3.1x	2.9x	2.4x	2.1x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.4	2.3	2.2	2.0	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	2.0	1.9	1.8	1.6	1.9
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.9x	2.5x	2.3x	1.9x	1.7x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.0	1.8	1.8	1.7	1.5	1.8
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.6	1.5	1.5	1.4	1.3	1.5
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	38.3	49.4	44.5	53.0	64.4	49.9
EFFECTIVE INCOME TAX RATE	38.9	33.9	28.1	16.8	8.0	25.1
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	67.2	43.9	33.1	21.7	19.7	37.1
COMMON DIVIDEND COVERAGE (5)	2.5x	2.2x	2.0x	1.8x	1.8x	2.1x

SEE PAGE 7 FOR NOTES.

NIAGARA MOHAWK POWER CORPORATION
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	19.1%	16.4%	18.4%	19.2%	15.4%	17.7%
MARKET/AVERAGE BOOK RATIO	79.5	92.6	81.6	70.8	70.2	78.9
DIVIDEND YIELD	13.3	11.2	12.2	13.1	12.4	12.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	46.4%	45.2%	46.8%	45.8%	48.0%	46.4%
PREFERRED STOCK	11.9	12.9	11.9	13.3	12.8	12.6
COMMON EQUITY	41.7	41.9	41.3	40.9	39.2	41.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	47.0%	46.2%	48.0%	47.6%	49.8%	47.7%
PREFERRED STOCK	11.8	12.6	11.6	12.8	12.4	12.3
COMMON EQUITY	41.2	41.2	40.4	39.6	37.8	40.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	14.9%	15.0%	14.7%	13.5%	10.8%	13.8%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.1x	3.0x	3.0x	2.7x	2.5x	2.9x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.5	2.5	2.5	2.5	2.3	2.5
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.1	2.1	2.1	2.0	1.8	2.0
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.4x	2.2x	2.0x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.8	2.0	2.0	2.0	1.8	1.9
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.5	1.6	1.6	1.6	1.5	1.6
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	52.4	43.6	41.0	38.6	44.2	44.0
EFFECTIVE INCOME TAX RATE	29.2	21.5	23.6	13.2	14.6	20.4
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	28.5	28.8	22.8	34.5	37.2	30.4
COMMON DIVIDEND COVERAGE (5)	1.8x	1.9x	1.7x	2.0x	2.1x	1.9x

SEE PAGE 7 FOR NOTES.

Exhibit JFB-2
Schedule 4
Page 3 of 7

PACIFIC GAS & ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	17.9%	14.0%	20.0%	15.6%	16.4%	16.8%
MARKET/AVERAGE BOOK RATIO	89.1	97.4	81.1	74.2	75.3	83.4
DIVIDEND YIELD	11.4	10.1	11.7	12.3	11.6	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	49.0%	45.3%	45.0%	45.7%	44.5%	45.9
PREFERRED STOCK	12.9	14.9	15.5	16.1	16.0	15.1
COMMON EQUITY	38.1	39.8	39.5	38.2	39.5	39.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	51.1%	47.3%	46.0%	50.4%	48.6%	48.7%
PREFERRED STOCK	12.3	14.4	15.2	14.7	14.8	14.3
COMMON EQUITY	36.6	38.3	38.8	34.9	36.6	37.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.0%	13.6%	16.0%	11.6%	12.0%	13.8%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.2x	3.2x	3.3x	2.3x	2.4x	2.9x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.3	2.4	2.1	2.2	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	1.8	1.9	1.7	1.8	1.8
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.6x	1.7x	1.8x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.7	1.6	1.8	1.6	1.6	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.4	1.3	1.4	1.2	1.3	1.3
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	59.2	68.4	54.4	66.1	61.0	61.8
EFFECTIVE INCOME TAX RATE	35.8	38.0	37.3	9.6	12.1	26.6
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	53.0	34.2	12.4	12.4	16.1	25.6
COMMON DIVIDEND COVERAGE (5)	2.6x	2.1x	1.3x	1.4x	1.5x	1.8x

SEE PAGE 7 FOR NOTES.

SAN DIEGO GAS & ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
INANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	14.5%	16.4%	19.6%	18.7%	8.3%	15.5%
MARKET/AVERAGE BOOK RATIO	109.8	111.1	90.4	78.3	73.3	92.6
DIVIDEND YIELD	9.8	9.7	11.8	13.0	12.7	11.4
APITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	46.4%	47.7%	42.4%	46.0%	47.9%	46.1%
PREFERRED STOCK	9.8	10.4	14.8	15.0	14.3	12.8
COMMON EQUITY	43.8	41.9	42.8	39.0	37.8	41.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	46.4%	49.6%	47.4%	51.3%	53.9%	49.7%
PREFERRED STOCK	9.8	10.0	13.5	13.5	12.6	11.9
COMMON EQUITY	43.8	40.4	39.1	35.2	33.5	38.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
ATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.0%	18.2%	17.8%	14.7%	6.2%	14.6%
OVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.9x	3.7x	3.0x	2.1x	1.5x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.6	2.7	2.5	2.0	1.6	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.2	2.2	2.0	1.7	1.3	1.9
OVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.7x	2.9x	2.4x	1.6x	1.0x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.0	1.8	1.5	1.1	1.8
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	1.6	1.4	1.3	1.0	1.5
UALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	14.7	48.8	54.1	54.4	114.3	57.3
EFFECTIVE INCOME TAX RATE	42.9	34.6	27.9	6.7	(19.5)	18.5
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	117.6	50.0	34.7	19.0	10.4	46.3
COMMON DIVIDEND COVERAGE (5)	3.2x	2.5x	2.1x	1.6x	1.3x	2.1x

SEE PAGE 7 FOR NOTES.

SIERRA PACIFIC RESOURCES
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	14.5%	11.9%	15.0%	12.7%	12.1%	13.2%
MARKET/AVERAGE BOOK RATIO	95.9	94.7	81.0	77.9	83.2	86.5
DIVIDEND YIELD	10.8	10.5	12.1	12.5	11.1	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	53.1%	52.5%	48.4%	50.2%	49.5%	50.7%
PREFERRED STOCK	9.1	10.4	11.7	13.0	14.3	11.7
COMMON EQUITY	37.8	37.1	39.9	36.8	36.2	37.6
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	53.4%	53.2%	51.2%	53.9%	51.4%	52.6%
PREFERRED STOCK	9.1	10.2	11.1	12.0	13.8	11.3
COMMON EQUITY	37.5	36.6	37.7	34.1	34.8	36.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	13.5%	11.3%	11.8%	10.1%	10.2%	11.4%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.8x	2.6x	2.5x	2.3x	2.3x	2.5x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.0	1.9	1.8	1.9	1.9
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.7	1.6	1.5	1.5	1.6
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.4x	1.9x	2.0x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.7	1.8	1.8	1.5	1.6	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.5	1.5	1.5	1.2	1.3	1.4
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	35.5	26.8	10.0	50.4	39.0	32.3
EFFECTIVE INCOME TAX RATE	41.0	39.7	39.3	33.0	30.4	36.7
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	53.2	58.3	71.5	24.4	18.7	45.2
COMMON DIVIDEND COVERAGE (5)	2.2x	2.7x	3.3x	2.2x	2.3x	2.5x

SEE PAGE 7 FOR NOTES.

SOUTH CALIFORNIA EDISON COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	15.3%	16.1%	15.8%	18.4%	14.7%	16.1%
MARKET/AVERAGE BOOK RATIO	107.0	106.1	94.5	79.6	70.5	91.5
DIVIDEND YIELD	9.5	9.3	10.2	11.3	11.6	10.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	45.8%	46.8%	48.3%	48.1%	47.5%	47.3%
PREFERRED STOCK	9.6	10.3	11.0	11.8	13.6	11.3
COMMON EQUITY	44.6	42.9	40.7	40.1	38.9	41.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	46.6%	47.9%	49.2%	50.1%	49.0%	48.5%
PREFERRED STOCK	9.4	10.1	10.8	11.4	13.2	11.0
COMMON EQUITY	44.0	42.0	40.0	38.5	37.8	40.5
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.4%	17.1%	15.2%	15.3%	10.7%	14.9%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.5x	3.0x	2.5x	2.8x	2.2x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.3	2.3	2.4	2.1	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.1	2.0	2.0	2.0	1.7	2.0
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.2x	2.3x	1.8x	2.2x	1.6x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.0	1.6	1.6	1.8	1.5	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.4	1.4	1.5	1.3	1.5
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	29.6	59.4	62.9	55.3	63.6	54.2
EFFECTIVE INCOME TAX RATE	45.4	35.5	12.1	21.7	2.6	23.5
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	83.8	48.4	23.9	18.1	15.8	38.0
COMMON DIVIDEND COVERAGE (5)	2.7x	2.1x	1.8x	1.7x	1.6x	2.0x

SEE PAGE 7 FOR NOTES.

Group of Five Electric Companies Having Incentive Fuel Clauses
Selected Risk Indices and Financial Ratios
1980-1984, Inclusive

Notes:

(1) Based upon financial statements as originally reported by each company in each year.

(2) Coverages - including all AFC - represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety included as income, cover fixed charges.

(3) Coverages - excluding all AFC - represent the number of times available earnings, excluding all AFC, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(5) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

(6) Arithmetic average of each company in the group.

Source of Information: Associated Utility Services Computerized Data Base
Standard & Poor's Compustat Services, Inc. Utility Compustat II

Current Bond Ratings of Philadelphia Electric Company and Five Companies Having Incentive Fuel Clauses

	November 1985 First Mortgage Bonds Debt Ratings	
	Moody's	S&P
Philadelphia Electric Company	Baa3	BBB-
Niagara Mohawk Power Corp.	A3	A-
Pacific Gas & Electric Co.	A1	A+
San Diego Gas & Electric Co.	Aa3	A+
Sierra Pacific Resources	Baa1	BBB+
Southern California Edison Co.	Aa2	AA

Source of Information: Moody's Public Utility Manual
S&P Bond Guide

Exhibit JFB-2
Schedule 6

Philadelphia Electric Company and Five Companies Having Incentive Fuel Clauses 1984 Size Comparison

	PECO	Niagara Mohawk Power Corp.	Southern California Edison Co.	Pacific Gas & Electric Company	San Diego Gas & Electric Company	Sierra Pacific Resources
			($ Million of Dollars)			
Revenues	$2,981	$2,786	$4,901	$7,830	$1,621	$358
Electric Revenue	2,436	2,134	4,899	5,159	1,291	285
Net Plant	8,460	5,402	10,071	13,345	2,393	786
Average Total Capital	7,628	5,015	9,341	13,567	2,366	712

Source of Information: Associated Utility Services Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II

PECo Exhibit JJC-1

R-850152
1/28/86 JK Hbg

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

EXHIBIT TO ACCOMPANY
SUPPLEMENTAL DIRECT TESTIMONY
OF
JOHN J. CARROLL

DATA REQUIREMENTS OF ECR NO. 8 ORDER, APPENDIX B

December 1985

Data Request (1), Data Request (1) (i)

Projected Energy Supply Mix
Projected Energy Prices
Information Provided Monthly by Class,
Unit, on a Monthly Basis

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ECTRIC GENERATION AND FUEL COST ESTIMATES

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
H						
L-PE STM.	153,000	146,000	146,000	114,000	146,000	186,000
AL-PE STM.	269,000	316,000	204,000	200,000	185,000	220,000
AL-MINEMTH	372,000	374,000	365,000	383,000	336,000	339,000
T.COMB.	17,220	32,910	14,980	7,590	7,810	4,240
TAL FOSSIL	811,220	868,910	729,980	704,590	674,810	749,240
H NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
T HYDRO	24,000	(7,000)	1,000	49,000	76,000	144,000
HER	0	0	0	0	0	0
CEIVED PJM	234,000	213,000	301,000	182,000	295,000	294,000
LIV'D PJM	(128,000)	(174,000)	(95,000)	(80,000)	(104,000)	(98,000)
EAM-HT PP	500	2,500	2,700	3,900	8,500	16,500
PPL & DPL	16	16	16	16	16	16
ARTY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
TCH & PUR	279,516	216,516	382,716	296,916	391,516	420,516
TAL OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
.-PE STM	8,291,000	7,906,000	8,068,000	6,730,000	8,006,000	10,020,000
AL-PE STM	5,537,000	6,504,000	4,206,000	4,175,000	3,884,000	4,661,000
NEMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
.COMB	1,128,000	2,168,800	966,400	475,500	493,500	262,500
AL FOSSIL	20,158,000	21,850,800	18,408,400	16,840,500	17,187,500	19,840,500
CLEAR EXCLUDING INTEREST, BUT INCLUDING OIL)						
LEAR.	12,899,724	12,713,952	10,067,749	9,915,663	9,442,991	9,990,157
ER	0	0	0	0	0	0
EIVED PJM	7,014,000	7,470,000	9,825,000	7,172,000	9,080,000	10,142,000
IV'D PJM	(5,636,000)	(7,447,000)	(4,149,000)	(3,135,000)	(5,235,000)	(4,695,000)
AM-HT PP	17,000	87,000	96,000	142,000	307,000	646,000
PPL & DPL	1,196	1,196	1,196	1,196	1,196	1,196
RTY TRANS	5,225,000	5,295,000	5,261,000	5,891,000	5,921,000	6,394,000
CH & PUR	6,621,196	5,406,196	11,034,196	10,071,196	10,074,196	12,488,196
ORMATION FOR RATE DIVISION ($'S EXCLUDE FUEL HANDLING)						
IN.CHGS	39,678,920	39,970,948	39,510,345	36,827,359	36,704,687	42,318,853
.CHGS	1,552,217	1,499,325	1,446,433	1,404,175	1,361,918	1,592,040
IN.CHGS	41,231,137	41,470,273	40,956,778	38,231,534	38,066,605	43,910,893
S $ INCLUDED IN COAL-PE STM)						
AL GAS	537,000	632,000	357,000	317,000	108,000	0
ORMATION FOR GEN. ACC. BUDGET GRP. (TOTAL FUEL HAND. $)						
L HANDL'G	839,735	831,978	812,520	816,886	810,367	810,703

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RIC GENERATION AND FUEL COST ESTIMATES

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
E STM.	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE STM.	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
INEMTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
MB.	11,770	12,380	2,610	12,280	2,240	4,230	130,260
FOSSIL	1,005,770	760,380	715,610	668,280	739,240	743,230	9,171,260
CLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
DRO	99,000	131,000	213,000	225,000	160,000	79,000	1,194,000
	0	0	0	0	0	0	0
ED PJM	136,000	282,000	259,000	418,000	387,000	725,000	3,726,000
'D PJM	(336,000)	(113,000)	(148,000)	(14,000)	(23,000)	(4,000)	(1,317,000)
-HT PP	22,200	15,600	12,100	5,100	1,900	2,300	93,800
L & DPL	16	16	16	16	16	16	192
Y TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
& PUR	9,216	350,616	295,116	565,116	506,916	867,316	4,581,992
OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494
E STM	15,134,000	8,923,000	6,507,000	5,958,000	4,788,000	7,531,000	97,862,000
PE STM	7,667,000	5,975,000	6,435,000	5,811,000	5,670,000	5,412,000	65,937,000
OUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
OMB	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200
FOSSIL	28,931,000	20,283,700	17,394,800	16,889,000	16,454,000	18,465,000	232,703,200
EAR EXCLUDING INTEREST, BUT INCLUDING OIL)							
AR.	12,152,686	9,143,637	9,859,519	5,990,617	6,791,025	6,357,607	115,325,327
	0	0	0	0	0	0	0
VED PJM	5,123,000	11,222,000	8,415,000	12,257,000	11,702,000	23,748,000	123,170,000
'D PJM	(17,798,000)	(6,301,000)	(6,655,000)	(764,000)	(725,000)	(237,000)	(62,777,000)
-HT PP	1,006,000	656,000	434,000	173,000	60,000	78,000	3,702,000
L & DPL	1,280	1,280	1,280	1,280	1,280	1,280	14,856
Y TRANS	5,852,000	5,199,000	5,392,000	4,939,000	4,471,000	4,558,000	64,398,000
& PUR	(5,815,720)	10,777,280	7,587,280	16,606,280	15,509,280	28,148,280	128,507,856
MATION FOR RATE DIVISION ($'S EXCLUDE FUEL HANDLING)							
.CHGS	35,267,966	40,204,617	34,841,599	39,485,897	38,754,305	52,970,887	476,536,383
HGS	1,546,272	1,500,504	1,786,919	1,723,429	1,673,874	1,624,317	18,711,423
.CHGS	36,814,238	41,705,121	36,628,518	41,209,326	40,428,179	54,595,204	495,247,806
$ INCLUDED IN COAL-PE STM)							
GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
MATION FOR GEN. ACC. BUDGET GRP. (TOTAL FUEL HAND. $)							
HANDL'G	0	0	0	0	0	0	4,922,189

H DISTRIBUTION 1 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
REHEAT OIL						
UYLKILL#1	25,000	21,000	24,000	5,000	22,000	22,000
DYSTONE#3	48,000	33,000	40,000	41,000	34,000	42,000
DYSTONE#4	43,000	51,000	50,000	36,000	32,000	30,000
DBY#2	0	0	0	0	40,000	53,000
.AHARE#7	20,000	20,000	17,000	19,000	17,000	20,000
.AHARE#8	17,000	21,000	15,000	13,000	1,000	19,000
I R H OIL	153,000	146,000	146,000	114,000	146,000	186,000
MARGINAL OIL						
CHMOND#9	0	0	0	0	0	0
UTHWARK#1	0	0	0	0	0	0
UTHWARK#2	0	0	0	0	0	0
I MARG OIL	0	0	0	0	0	0
EAT & MARGINAL OIL I OIL	153,000	146,000	146,000	114,000	146,000	186,000
COAL						
DYSTONE#1	104,000	118,000	115,000	129,000	121,000	106,000
DYSTONE#2	115,000	139,000	30,000	0	0	40,000
MBY#1	50,000	59,000	59,000	71,000	64,000	74,000
I COAL	269,000	316,000	204,000	200,000	185,000	220,000
LA. AREA OIL AND COAL. LA STEAM	422,000	462,000	350,000	314,000	331,000	406,000
O - STATION TOTALS						
DYSTONE	310,000	341,000	235,000	206,000	187,000	218,000
MBY	50,000	59,000	59,000	71,000	104,000	127,000
AHARE7&8	37,000	41,000	32,000	32,000	18,000	39,000
UTHWARK1&2	0	0	0	0	0	0

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DISTRIBUTION 1 OF 4

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	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
EHEAT OIL							
YLKILL#1	45,000	24,000	21,000	14,000	9,000	14,000	246,000
STONE#3	67,000	18,000	12,000	24,000	16,000	37,000	412,000
STONE#4	66,000	62,000	13,000	12,000	20,000	20,000	435,000
BY#2	44,000	12,000	44,000	32,000	25,000	38,000	288,000
ARE#7	34,000	19,000	12,000	10,000	3,000	12,000	203,000
ARE#8	21,000	21,000	11,000	10,000	5,000	11,000	165,000
H OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
RGINAL OIL							
OND#9	0	0	0	0	0	0	0
HARK#1	0	0	0	0	0	0	0
HARK#2	0	0	0	0	0	0	0
ARG OIL	0	0	0	0	0	0	0
T & MARGINAL OIL IL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
L							
ONE#1	124,000	111,000	108,000	117,000	110,000	101,000	1,364,000
ONE#2	147,000	98,000	133,000	126,000	130,000	97,000	1,055,000
#1	84,000	68,000	55,000	28,000	24,000	53,000	689,000
AL	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
AREA OIL AND COAL. STEAM	632,000	433,000	409,000	373,000	342,000	383,000	4,857,000
STATION TOTALS							
ONE	404,000	289,000	266,000	279,000	276,000	255,000	3,266,000
	128,000	80,000	99,000	60,000	49,000	91,000	977,000
RE7&8	55,000	40,000	23,000	20,000	8,000	23,000	368,000
ARK1&2	0	0	0	0	0	0	0

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DISTRIBUTION 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
EMOUTH (PE SHARE)						
STONE#1	107,000	108,000	95,000	109,000	94,000	90,000
STONE#2	96,000	84,000	88,000	96,000	85,000	90,000
STONE STA	203,000	192,000	183,000	205,000	179,000	180,000
EHAUGH#1	81,000	96,000	87,000	86,000	79,000	85,000
EHAUGH#2	88,000	86,000	95,000	92,000	78,000	74,000
EHAUGHSTA	169,000	182,000	182,000	178,000	157,000	159,000
EMOUTH	372,000	374,000	365,000	383,000	336,000	339,000
LA. AREA OIL & COAL, AND MINEMOUTH COAL.						
SIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
LEAR (PE SHARE)						
CH BOT#2	258,117	281,339	252,759	216,140	290,270	208,102
CH BOT#3	229,561	272,658	206,693	188,222	132,811	266,502
BOT STA	487,678	553,997	459,452	404,362	423,081	474,604
EM#1	282,000	264,000	242,000	247,000	274,000	247,000
EM#2	317,000	273,000	136,000	0	0	21,000
EH STA	599,000	537,000	378,000	247,000	274,000	268,000
1	663,000	629,000	511,000	643,000	546,000	565,000
2	0	0	0	0	0	0
STA	663,000	629,000	511,000	643,000	546,000	565,000
NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
ER (PRECOMMERCIAL)						
ERICK 1	0	0	0	0	0	0
ERICK 2	0	0	0	0	0	0
ER	0	0	0	0	0	0

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	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
UTH (PE SHARE)							
NE#1	93,000	90,000	111,000	21,000	84,000	101,000	1,103,000
NE#2	81,000	81,000	94,000	92,000	107,000	92,000	1,086,000
NE STA	174,000	171,000	205,000	113,000	191,000	193,000	2,189,000
UGH#1	96,000	82,000	93,000	87,000	102,000	86,000	1,060,000
UGH#2	92,000	62,000	6,000	83,000	102,000	77,000	935,000
UGHSTA	188,000	144,000	99,000	170,000	204,000	163,000	1,995,000
UTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
AREA OIL & COAL, AND MINEMOUTH COAL.							
STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
R (PE SHARE)							
BOT#2	276,873	14,290	0	0	248,293	275,980	2,322,163
BOT#3	259,465	228,681	237,790	246,797	156,899	0	2,426,079
T STA	536,338	242,971	237,790	246,797	405,192	275,980	4,748,242
1	263,000	257,000	283,000	281,000	300,000	287,000	3,227,000
2	255,000	209,000	207,000	275,000	210,000	302,000	2,205,000
STA	518,000	466,000	490,000	556,000	510,000	589,000	5,432,000
	561,000	486,000	555,000	0	0	0	5,159,000
	0	0	0	0	0	0	0
A	561,000	486,000	555,000	0	0	0	5,159,000
CLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
(PRECOMMERCIAL)							
CK 1	0	0	0	0	0	0	0
CK 2	0	0	0	0	0	C	0
	0	0	0	0	0	0	0

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	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
SELS						
BY D 1&2	20	0	0	0	100	40
AHARE D	20	20	0	20	40	0
THMARK D	0	0	0	0	0	0
YLKILL D	0	0	20	10	0	0
DIESELS	40	20	20	30	140	40
STONE D	10	20	20	0	0	0
EMAUGH D	10	20	20	0	0	0
SEL	60	60	60	30	140	40
TURBINES						
H GE CT	2,750	6,170	2,240	1,060	1,770	0
H NE CT	0	0	0	0	0	0
H NO CT	0	0	0	0	0	0
CT TOTAL	2,750	6,170	2,240	1,060	1,770	0
THMARK CT	210	870	400	0	0	0
YSTONE CT	280	880	360	0	0	0
AHARE CT	270	830	400	0	0	0
UYLKILLCT	110	480	100	0	0	0
STER CT	210	630	300	0	0	0
LS CT	360	790	360	0	0	0
ER CT	240	840	330	0	0	0
MTG CT	0	0	0	0	0	0
UBTOTAL	4,430	11,490	4,490	1,060	1,770	0
YDON	12,700	21,300	10,400	6,500	5,900	4,200
TURBINES	17,130	32,790	14,890	7,560	7,670	4,200
EM CT	30	60	30	0	0	0
AL CT	17,160	32,850	14,920	7,560	7,670	4,200
AL CT AND DIESEL AL IC	17,220	32,910	14,980	7,590	7,810	4,240
PLE CYCLE (INC. SALEM CT) TOTAL	4,460	11,550	4,520	1,060	1,770	0

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ISTRIBUTION 3 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
LS							
Y D 1&2	0	60	10	0	0	0	230
ARE D	170	40	0	60	0	0	370
HARK D	0	0	0	0	0	0	0
LKILL D	40	0	0	0	0	0	70
ESELS	210	100	10	60	0	0	670
ONE D	0	0	0	10	0	0	60
AUGH D	0	0	0	10	0	0	60
L	210	100	10	80	0	0	790
URBINES							
GE CT	860	280	0	2,830	240	930	19,130
NE CT	0	0	0	0	0	0	0
NO CT	0	0	0	0	0	0	0
T TOTAL	860	280	0	2,830	240	930	19,130
HARK CT	0	0	0	120	0	0	1,600
TONE CT	0	0	0	150	0	0	1,670
ARE CT	0	0	0	330	0	0	1,830
LKILLCT	0	0	0	30	0	0	720
ER CT	0	0	0	180	0	0	1,320
CT	0	0	0	220	0	0	1,730
CT	0	0	0	210	0	0	1,620
TG CT	0	0	0	0	0	0	0
TOTAL	860	280	0	4,070	240	930	29,620
ON	10,700	12,000	2,600	8,100	2,000	3,300	99,700
URBINES	11,560	12,280	2,600	12,170	2,240	4,230	129,320
CT	0	0	0	30	0	0	150
. CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
. CT AND DIESEL . IC	11,770	12,380	2,610	12,280	2,240	4,230	130,260
E CYCLE (INC. SALEM CT) TAL	860	280	0	4,100	240	930	29,770

H DISTRIBUTION 4 OF 4 (SUMMARY)

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	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
. STEAM	153,000	146,000	146,000	114,000	146,000	166,000
OAL STEAM	269,000	316,000	204,000	200,000	185,000	220,000
EMOUTH	372,000	374,000	365,000	383,000	336,000	339,000
SIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
ER	0	0	0	0	0	0
SEL	60	60	60	30	140	40
AL CT	17,160	32,850	14,920	7,560	7,670	4,200
INTCH	106,000	39,000	206,000	102,000	191,000	196,000
POWER	516	2,516	2,716	3,916	8,516	16,516
RTY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
MINGO	79,000	57,000	52,000	85,000	123,000	181,000
Y RUN	143,000	112,000	114,000	95,000	81,000	106,000
INPUT	(198,000)	(176,000)	(165,000)	(131,000)	(128,000)	(143,000)
L OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360

E: THIS PAGE EXCLUDES SALEM #2 WHILE SOLD TO J.C.

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H DISTRIBUTION 4 OF 4 (SUMMARY)

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	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
L STEAM	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
COAL STEAM	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
NEMOUTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
SSIL STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
ER	0	0	0	0	0	0	0
SEL	210	100	10	80	0	0	790
AL CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
INTCH	(200,000)	169,000	111,000	404,000	364,000	721,000	2,409,000
POWER	22,216	15,616	12,116	5,116	1,916	2,316	93,992
TY TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
HINGO	138,000	172,000	259,000	258,000	205,000	123,000	1,732,000
Y RUN	90,000	91,000	96,000	81,000	80,000	116,000	1,205,000
INPUT	(129,000)	(132,000)	(142,000)	(114,000)	(125,000)	(160,000)	(1,743,000)
OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494

THIS PAGE EXCLUDES SALEM #2 WHILE SOLD TO J.C.

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EL COST 1 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
L (NO.6 & NO. 2)						
HUYLKILL#1	1,146,000	936,000	1,122,000	227,000	1,015,000	1,059,000
DYSTONE1&2	182,000	166,000	186,000	195,000	164,000	210,000
DYSTONE3&4	5,185,000	4,852,000	5,147,000	4,643,000	4,086,000	4,460,000
DY 1,2,3,4	5,367,000	5,018,000	5,333,000	4,838,000	4,250,000	4,670,000
(SULFUR)	0	0	0	0	224,000	424,000
DYSTONE	5,367,000	5,018,000	5,333,000	4,838,000	4,474,000	5,094,000
DDBY#1	16,000	14,000	14,000	11,000	11,000	10,000
DDBY#2	35,000	35,000	34,000	36,000	1,800,000	2,364,000
(SULFUR)	135,000	160,000	159,000	198,000	178,000	205,000
DDBY	186,000	209,000	207,000	245,000	1,989,000	2,579,000
LAWARE 7&8	1,727,000	1,903,000	1,565,000	1,618,000	930,000	1,917,000
CHMOND	0	0	0	0	0	0
UTHWARK1&2	0	0	0	0	0	0
TAL OIL	8,426,000	8,066,000	8,227,000	6,928,000	8,408,000	10,649,000
AL						
DYSTONE#1	1,880,000	2,122,000	2,086,000	2,376,000	2,222,000	1,956,000
DYSTONE#2	2,090,000	2,533,000	553,000	0	0	750,000
DYSTONE	3,970,000	4,655,000	2,639,000	2,376,000	2,222,000	2,706,000
DDBY#1	895,000	1,057,000	1,051,000	1,284,000	1,152,000	1,326,000
TAL PECOAL	4,865,000	5,712,000	3,690,000	3,660,000	3,374,000	4,032,000
S FOR SCRUBBER						
DYSTONE#1	256,000	290,000	282,000	317,000	108,000	0
DYSTONE#2	281,000	342,000	75,000	0	0	0
TAL GAS	537,000	632,000	357,000	317,000	108,000	0
TAL OIL, TOTAL COAL & TOTAL GAS						
LA STEAM	13,828,000	14,410,000	12,274,000	10,905,000	11,890,000	14,681,000

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L COST 1 OF 4

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(NO.6 & NO. 2)	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
UYLKILL#1	2,173,000	1,181,000	1,032,000	689,000	463,000	687,000	11,730,000
YSTONE1&2	227,000	201,000	202,000	171,000	203,000	232,000	2,339,000
YSTONE3&4	7,895,000	4,864,000	1,946,000	2,538,000	2,484,000	3,653,000	51,753,000
1,2,3,4	8,122,000	5,065,000	2,148,000	2,709,000	2,687,000	3,885,000	54,092,000
SULFUR)	818,000	629,000	677,000	0	0	0	2,772,000
YSTONE	8,940,000	5,694,000	2,825,000	2,709,000	2,687,000	3,885,000	56,864,000
BY#1	7,000	9,000	16,000	10,000	7,000	16,000	141,000
BY#2	2,035,000	641,000	2,066,000	1,501,000	1,203,000	1,757,000	13,507,000
SULFUR)	246,000	199,000	158,000	80,000	68,000	150,000	1,936,000
BY	2,288,000	849,000	2,240,000	1,591,000	1,278,000	1,923,000	15,584,000
MARE 7&8	2,797,000	2,027,000	1,245,000	1,049,000	428,000	1,186,000	18,392,000
MONO	0	0	0	0	0	0	0
HMARK1&2	0	0	0	0	0	0	0
L OIL	16,198,000	9,751,000	7,342,000	6,038,000	4,856,000	7,681,000	102,570,000
STONE#1	2,312,000	2,056,000	2,031,000	2,200,000	2,087,000	1,921,000	25,249,000
STONE#2	2,751,000	1,845,000	2,518,000	2,407,000	2,475,000	1,870,000	19,792,000
STONE	5,063,000	3,901,000	4,549,000	4,607,000	4,562,000	3,791,000	45,041,000
BY#1	1,540,000	1,246,000	1,010,000	528,000	454,000	986,000	12,529,000
. PECOAL	6,603,000	5,147,000	5,559,000	5,135,000	5,016,000	4,777,000	57,570,000
OR SCRUBBER							
TONE#1	0	0	18,000	286,000	268,000	247,000	2,072,000
TONE#2	0	0	23,000	310,000	318,000	238,000	1,587,000
GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
OIL, TOTAL COAL & TOTAL GAS STEAM	22,801,000	14,898,000	12,942,000	11,769,000	10,458,000	12,943,000	163,799,000

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FUEL COST 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MINEMOUTH (PE SHARE)						
KEYSTN1 COAL	1,348,000	1,361,000	1,196,000	1,404,000	1,208,000	1,160,000
KEYSTN2 COAL	1,213,000	1,054,000	1,112,000	1,225,000	1,094,000	1,155,000
KEYSTONE C	2,561,000	2,415,000	2,308,000	2,629,000	2,302,000	2,315,000
KEYST1&2 OIL	0	17,000	16,000	0	9,000	43,000
KEYSTONE	2,561,000	2,432,000	2,324,000	2,629,000	2,311,000	2,358,000
CON1 COAL	1,260,000	1,491,000	1,352,000	1,357,000	1,249,000	1,345,000
CON2 COAL	1,374,000	1,342,000	1,485,000	1,460,000	1,230,000	1,166,000
CONEMAUGH C	2,634,000	2,833,000	2,837,000	2,817,000	2,479,000	2,511,000
CON1&2 OIL	7,000	7,000	7,000	14,000	14,000	28,000
CONEMAUGH	2,641,000	2,840,000	2,844,000	2,831,000	2,493,000	2,539,000
MINEMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
NUCLEAR (PE SHARE)						
PB2 NUCLEAR	1,786,023	1,946,704	1,748,943	1,495,563	2,008,504	1,439,942
PB3 NUCLEAR	1,739,358	2,065,905	1,566,089	1,426,140	1,006,295	2,019,255
PB2&3INTREST	813,118	786,265	759,413	732,559	705,706	678,854
PB ATOMIC	4,338,499	4,798,874	4,074,445	3,654,262	3,720,505	4,138,051
AUX BOILER	28,778	28,778	27,900	29,698	28,740	29,698
PB DIESEL	4,494	4,494	4,352	4,552	4,404	4,552
SALEM 1	2,086,000	1,953,000	1,795,000	1,831,000	2,033,000	1,831,000
SALEM 2	1,976,000	1,703,000	848,000	0	0	152,000
SLM1INTEREST	401,915	466,511	451,107	435,703	420,299	404,895
SLM2INTEREST	257,184	246,549	235,913	235,913	235,913	508,291
SALEM AUXBLR	0	0	0	0	0	0
SALEM DIESEL	200	200	200	200	200	200
LM1 NUCLEAR	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
LM2 NUCLEAR	0	0	0	0	0	0
LM NUC TOTAL	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
LIMAUXBOILER	43,749	43,749	42,368	44,299	42,869	44,299
LIM DIESEL	7,122	7,122	6,897	7,211	6,979	7,211
NUCLEAR	14,451,941	14,213,277	11,514,182	11,319,838	10,804,909	11,582,197
NOTE: FOR JIM MILLER						
SALEM JC2	0	0	0	0	0	0
OTHER (PRECOMMERCIAL)						
OTHER	0	0	0	0	0	0

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	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MINEMOUTH (PE SHARE)							
KEYSTN1 COAL	1,208,000	1,177,000	1,449,000	271,000	1,112,000	1,333,000	14,227,000
KEYSTN2 COAL	1,057,000	1,056,000	1,227,000	1,210,000	1,408,000	1,214,000	14,025,000
KEYSTONE C	2,265,000	2,233,000	2,676,000	1,481,000	2,520,000	2,547,000	28,252,000
KEYST1&2 OIL	27,000	18,000	0	0	18,000	0	148,000
KEYSTONE	2,292,000	2,251,000	2,676,000	1,481,000	2,538,000	2,547,000	28,400,000
CON1 COAL	1,543,000	1,323,000	1,498,000	1,415,000	1,657,000	1,409,000	16,899,000
CON2 COAL	1,478,000	996,000	102,000	1,357,000	1,653,000	1,252,000	14,895,000
CONEMAUGH C	3,021,000	2,319,000	1,600,000	2,772,000	3,310,000	2,661,000	31,794,000
CON1&2 OIL	16,000	8,000	7,000	7,000	0	22,000	137,000
CONEMAUGH	3,037,000	2,327,000	1,607,000	2,779,000	3,310,000	2,683,000	31,931,000
MINEMOUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
NUCLEAR (PE SHARE)							
PB2 NUCLEAR	1,915,803	98,880	0	0	1,798,577	1,999,138	16,238,077
PB3 NUCLEAR	1,965,941	1,732,694	1,802,039	1,875,236	1,192,160	0	18,391,112
PB2&3INTREST	664,921	650,987	969,237	937,582	919,860	902,138	9,520,640
PB ATOMIC	4,546,665	2,482,561	2,771,276	2,812,818	3,910,597	2,901,276	44,149,829
AUX BOILER	31,138	28,124	30,898	29,302	30,278	29,346	352,678
PB DIESEL	4,920	4,444	4,902	4,698	4,856	4,702	55,370
SALEM 1	1,946,000	1,906,000	2,095,000	2,081,000	2,223,000	2,129,000	23,909,000
SALEM 2	1,805,000	1,481,000	1,468,000	1,947,000	1,487,000	2,142,000	15,009,000
SLM1INTEREST	389,491	374,087	358,683	343,279	327,876	312,472	4,766,318
SLM2INTEREST	491,860	475,430	458,999	442,568	426,138	409,707	4,424,465
SALEM AUXBLR	0	0	0	0	0	0	0
SALEM DIESEL	200	200	200	200	200	200	2,400
LM1 NUCLEAR	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
LM2 NUCLEAR	0	0	0	0	0	0	0
LM NUC TOTAL	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
LIMAUXBOILER	47,888	43,254	47,713	45,736	47,260	45,770	538,954
LIM DIESEL	7,796	7,041	7,767	7,445	7,694	7,451	87,736
NUCLEAR	13,698,958	10,644,141	11,646,438	7,714,046	8,464,899	7,981,924	134,036,750
NOTE: FOR JIM MILLER							
SALEM JC2	0	0	0	0	0	0	0
OTHER (PRECOMMERCIAL)							
OTHER	0	0	0	0	0	0	0

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FUEL COST 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
DIESELS						
CROMBY D 1&2	1,400	0	0	0	5,800	2,500
DELAWARE D	1,400	1,400	0	1,100	2,500	0
SOUTHWARK D	0	0	0	0	0	0
SCHUYLKILL D	0	0	1,400	400	0	0
KEYSTONE D	800	1,400	1,000	0	200	0
CONEMAUGH D	400	1,000	1,000	0	0	0
DIESEL	4,000	3,800	3,400	1,500	8,500	2,500
GAS TURBINES						
SOUTHWARK CT	17,000	69,000	31,000	0	0	0
EDDYSTONE CT	23,000	72,000	29,000	0	0	0
DELAWARE CT	23,000	67,000	32,000	0	0	0
SCHUYLKILLCT	9,000	38,000	8,000	0	0	0
CHESTER CT	17,000	50,000	23,000	0	0	0
FALLS CT	29,000	63,000	29,000	0	0	0
MOSER CT	20,000	68,000	26,000	0	0	0
PLY MTG CT	0	0	0	0	0	0
RICH GE CT	185,000	412,000	150,000	72,000	120,000	0
RICH WE CT	0	0	0	0	0	0
RICH NO CT	0	0	0	0	0	0
RICHMOND CT	185,000	412,000	150,000	72,000	120,000	0
CROYDON	798,000	1,321,000	632,000	402,000	365,000	260,000
SALEM CT	3,000	5,000	3,000	0	0	0
GAS TURBINES	1,124,000	2,165,000	963,000	474,000	485,000	260,000
TOTAL IC	1,128,000	2,168,800	966,400	475,500	493,500	262,500

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	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
DIESELS							
CROMBY D 182	0	4,000	800	0	0	0	14,500
DELAWARE D	11,300	2,700	0	3,800	0	0	24,200
SOUTHWARK D	0	0	0	0	0	0	0
SCHUYLKILL D	2,700	0	0	0	0	0	4,500
KEYSTONE D	0	0	0	600	0	0	4,000
CONEMAUGH D	0	0	0	600	0	0	3,000
DIESEL	14,000	6,700	800	5,000	0	0	50,200
GAS TURBINES							
SOUTHWARK CT	0	0	0	11,000	0	0	128,000
EDDYSTONE CT	0	0	0	14,000	0	0	138,000
DELAWARE CT	0	0	0	29,000	0	0	151,000
SCHUYLKILLCT	0	0	0	3,000	0	0	58,000
CHESTER CT	0	0	0	17,000	0	0	107,000
FALLS CT	0	0	0	19,000	0	0	140,000
MOSER CT	0	0	0	19,000	0	0	133,000
PLY MTG CT	0	0	0	0	0	0	0
RICH GE CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
RICH WE CT	0	0	0	0	0	0	0
RICH NO CT	0	0	0	0	0	0	0
RICHMOND CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
CROYDON	723,000	780,000	169,000	537,000	131,000	226,000	6,344,000
SALEM CT	0	0	0	2,000	0	0	13,000
GAS TURBINES	787,000	801,000	169,000	855,000	148,000	292,000	8,523,000
TOTAL IC	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200