APPENDIX B

PECO STATEMENT NO. 3A

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

REBUTTAL TESTIMONY OF
JOSEPH F. PAQUETTE, JR.

FINANCIAL IMPACT OF OPPOSING
PARTY RATE PROPOSALS;
ADDITIONAL FINANCINGS
REQUIRED UNDER THE OKA
HYPOTHETICAL LIMERICK
CONSTRUCTION SCHEDULE

February 19, 1986

increase recommendations which have been presented in this case?

A. It is obvious that the extreme positions proposed by the PUC Staff, the OCA and the City of Philadelphia would cause irreparable harm to the Company, its shareholders and its customers. The GEC's position is more reasonable, but it contains fundamental timing problems which make it unfair to present and future ratepayers by jeopardizing the Company's construction program while at the same time imposing larger rate increases on future customers. I believe that only the Company's proposed rate increase and phase-in plan achieve the desired objective of balancing (1) the needs of our current customers who are being served by Limerick, (2) the needs of our future customers who must depend on the Company for an adequate and dependable supply of electricity for many years to come, (3) the interests of our investors who have provided the $3.8 billion of capital for Limerick in anticipation that the regulatory process would provide a fair return on and an orderly return of their investment, and (4) the requirements of the financial markets if we are to raise the capital for our future financial needs.

Q. Mr. Paquette, why did you develop a hypothetical financing plan consistent with the OKA construction schedule?

A. I am aware that Mr. Boyer's Supplemental Testimony documents his opinion that the Company could not have completed Limerick No. 1 before February 1986 even if there had been no cash constraints which limited the construction schedule in the 1970's. Nevertheless, I have developed a hypothetical financing plan which would be consistent with the OKA construction schedule. The purpose of this exercise is to develop data to be utilized by Mr. Hill in his assessment of the overall impact of the OKA plan on our revenue requirements over the entire construction phase and operating life of Limerick considering all appropriate factors. Specifically, my study will provide Mr. Hill with the change in revenue requirements that would have resulted from the OKA plan during the construction period and the changes that would have resulted in the Company's AFUDC rate as a result of the hypothetical financing plan.

Q. Mr. Paquette, would you now please discuss how the Company developed its hypothetical OKA financing schedule?

A. To accommodate the additional financing that would have been necessary to put Limerick Unit No. 1 in commercial operation on November 20, 1983, we have utilized the direct costs in the OKA proposed schedule (OCA Statement No. 1A) but have included the additional PURTA taxes and overheads which would have been capitalized, and we have utilized the recalculated AFUDC reflecting the AFUDC rate which would have been in effect under the hypothetical OKA financing program. Table 3 shows the yearly changes which the corrected OKA construction schedule would have produced in our financing program.

We have employed the most conservative assumptions in order to determine the specific nature and terms of the financing required each year. As will be discussed below, the OKA construction plan would have required us to raise $929 million of additional capital in the period 1975 to 1982. Despite the fact that the Company's actual financial condition was extremely weak during this period, we have assumed, for purposes of this study, that we would have raised that additional amount of capital without suffering any further downgrading in our security ratings.

In order to roughly simulate the same financial condition which actually existed, we adjusted revenue, up or down, each year to maintain earnings per share at exactly the same amount each year as was historically recorded. These revenue changes are employed by Mr. Hill to compute the impact on our customers' bills during the period 1975-1985. We also calculated the amount of revenue increases required to maintain the same mortgage coverage ratios throughout the construction period. This was necessary because simple maintenance of dollar earnings per share did not in fact maintain our financial position, but in fact permitted a significant deterioration.

In our hypothetical study, we attempted to add financing in a manner which duplicates our actual historical capitalization ratios as closely as possible. Where possible, we increased an actual financing, and, for the most part, we assumed no penalty for increasing the size of an issue. We increased the size of existing issues in whole dollar amounts or round share amounts to reflect the practicalities of the real world and limited the size of the issues to that which we felt were capable of being sold at the time. If we were required to create a new financing, we assigned a rate for comparably rated securities, obtained from Moody's historical data. The timing of each new issue was determined by the pattern of the actual financings so as to best fit in with the existing financing program. Our ability to sell mortgage bonds and preferred stock was governed by our coverage ratios.

Q. Would you please describe the hypothetical OKA financing changes year by year?

A. Yes. Table 4 shows a summary of the year-by-year changes which the OKA schedule would have required utilizing the assumptions listed above. Table 5 shows the details of each issue discussed below.

<u>1975 ($45.7 Million Required)</u>

To provide the additional financing of $45.7 million, we first assumed that the $80 million August mortgage bond issue was increased to $100 million. Next, the

September common stock issue of 6 million shares was increased by 1.3 million shares to raise an additional $15.9 million. The remaining $9.8 million was assumed to be raised from short-term debt.

1976 ($43.9 Million Required)

We assumed that the additional required financing of $43.9 million was raised through the sale of common stock and an increase in the short-term debt balance because the size of the actual mortgage bond issues and preferred stock issues could not have been increased. The October common stock sale was increased from 4 to 5.5 million shares, raising $26.3 million, and the short-term debt balance was increased by $17.6 million.

1977 ($58.9 Million Required)

The two actual issues of mortgage bonds in March and July were each $75 million, and we have assumed that each issue was increased to $100 million, representing the maximum size of an issue able to be sold at that time. In addition, we increased the size of the October common stock issue from 4 million to 5.2 million shares, raising another $24.2 million. This amount of assumed financing was in excess of the requirement and allowed us to reduce short-term debt by $15.3 million.

1978 ($86.4 Million Required)

We assumed that the size of the $100 million bond issue sold in March could not be increased. Therefore, in order to raise the necessary capital and to maintain historical capitalization ratios, we assumed a new issue of $75.0 million of mortgage bonds in September. The additional requirement of $11.4 million was raised through short-term debt.

1979 ($123.3 Million Required)

In 1979, the Company was still experiencing an inability to sell preferred stock due to insufficient coverages. Therefore, the amount to be financed is split between debt and common stock. Mortgage coverage was marginal at year-end; and, if the new issue were assumed to have been mortgage bonds in the beginning of the year, it might have jeopardized the actual October issue of $100 million of mortgage bonds. Therefore, it was assumed that $50 million of debentures would be issued in March. In addition, we assumed a 4 million share issue of common stock in October which raised $60 million. Short term debt was increased by $13.3 million to provide the remainder of the funds.

1980 ($178.4 Million Required)

At this time the Company was still experiencing coverage problems with respect to the issuance of debt. Therefore, we assumed the issuance of $100 million of debentures in July.

The Company actually sold $72 million of preferred stock, and it was assumed that additional preferred stock could not be sold.

The balance of the funds would be raised through the sale of 4 million shares of common stock in September in the amount of $57.5 million which followed the actual sale of 7 million shares in July. Short term debt was increased $20.9 million.

1981 ($230.6 Million Required)

In actual practice, the Company sold $424 million of debt in 1981 in the form of mortgage bonds and pollution control notes in sales in April, June, July and September. At this point in time, it is assumed that the Company could not have raised additional mortgage bonds and would have been required to sell debt in the form of debentures. Therefore, we assumed the sale of $125 million of debentures in December. There was no preferred stock actually sold in 1981, so we assumed a $50 million sale of preferred stock in February. The actual common stock issue in September was increased by 4 million shares to raise an additional $49.5 million, and the September common issue was increased by 1.2 million shares, which provides $15.3 million. These financings enabled us to reduce short term debt by $9.2 million.

1982 ($161.7 Million Required)

The Company sold $320 million of debt in 1982 in the form of mortgage bonds, pollution control notes and serial notes in March, June, September and December. It was assumed that any additional debt financing would have to be in the form of debentures. Therefore, we assumed a $100 million debenture issue in July. The Company sold $30 million of preferred stock in February which we assumed could be increased by $20 million to $50 million but at an increased cost of 17.50% (instead of 17-1/8%). We also assumed that both of the 6 million share common stock issues in April and October were increased by 3 million shares, raising an additional $90.4 million. Total financing would permit us to reduce short-term debt by $48.7 million.

1983 ($197.6 Million Lower Requirement)

As a result of the earlier in-service date of Limerick Unit No. 1 as proposed by OKA, the amount of financing required in 1983 would have been reduced by $197.6 million. At the end of 1983, the Company borrowed $200 million under its $400 million domestic revolving credit/term loan agreement. We assumed that this borrowing and also the $800 million Limerick Credit Agreement (LCA) would not have taken place if Limerick Unit No. 1 had been placed in commercial operation in 1983. However, in order to maintain the appropriate capitalization ratios, we have eliminated the sale of 6.0 million shares of common stock in March ($104 million) and substituted a $100 million issue of mortgage bonds. As a result, short-term debt would have to be increased by $6.4 million.

<u>1984 ($664.5 Million Lower Requirement)</u>

Likewise, in 1984 the amount of financing would have been reduced significantly. The required reduction is $664.5 million. The effect of this reduction would have been essentially to have eliminated all the equity financing -- both common and preferred — except for that sold through the various stock plans. As noted above, we have eliminated the borrowings under the LCA as well as the pollution control financing for Limerick which would not have been possible under the OKA schedule. We have also assumed a new $100 million issue of mortgage bonds to maintain the appropriate capitalization ratios. As a result, short-term debt would have been reduced by $65.6 million.

<u>1985 ($473.4 Million Lower Requirement)</u>

The amount of financing reduction for 1985 would have amounted to $473.4 million. This would have resulted in the elimination of all equity financing, including the assumed elimination of the Company's Dividend Reinvestment and Stock Purchase Plan but maintaining the employee plans. Consistently with the above-mentioned assumptions, we eliminated the borrowing under the LCA and the Limerick pollution control financing. In addition, we reduced each of the November mortgage bond issues by $50 million. As a result, short-term debt would have increased by $44.2 million.

Q. Would you please summarize the changes that the hypothetical OKA financing plan would have produced?

A. Table 6 presents a summary of the capital structure that results from the hypothetical OKA financing plan for the period 1975 through 1985 as compared with the actual PE structure. As indicated on Table 6, the hypothetical OKA financing plan would have maintained the various capitalization ratios at a level very close to actual for every year in the study. In addition, our short-term position would have been reduced by only $15.2 million through December 31, 1985.

Table 7 shows a comparison of the key financial ratios (earnings per share, AFUDC as a % of earnings, mortgage coverage ratio and preferred stock ratio) for the hypothetical and actual financing programs. As indicated above, we programmed earnings per share under the hypothetical OKA plan to be identical to the actual earnings per share. However, the percentage of earnings represented by AFUDC increased significantly under the hypothetical plan in some years, resulting in a reduction in the quality of earnings. In addition, we would have experienced a lower mortgage coverage ratio during the entire period 1975 to 1983, inclusive, under the hypothetical OKA plan. Of particular concern is the period 1977 to 1981 when the OKA plan would have shown a serious decline in mortgage coverage, especially in 1979 when the ratio was only 1.88 times. I have calculated that approximately $195 million of additional revenue would have been required during the period 1975-83 to prevent this serious decline in mortgage coverage ratios under the OKA plan, in addition to the revenue needed to maintain earnings per share.

Q. Mr. Paquette, what are your conclusions regarding this study relating to the hypothetical OKA financing?

A. I believe that the hypothetical financing plan outlined is extremely optimistic in terms of the availability of capital and the cost of capital. In the period from 1973 to 1980, in particular, we were operating in a capital market environment which was extremely volatile and nervous. Even if we assume that it would have been possible to raise the required capital, it would probably have necessitated a significant increase in the cost of the capital and undoubtedly a downgrading of our security ratings, which would have further increased the costs of the OKA plan and resulted in higher rates for our customers.

Q. Mr. Sanders has expressed his opinion that the Company would have experienced a downgrading in its security ratings if it had attempted to pursue the OKA financing plan. Can you assess the cost impact of a downgrading if one had occurred in 1976?

A. If our mortgage bond rating had been downgraded to BBB in 1976, that would have probably increased the cost of all the securities we issued until 1983, assuming we were able to raise the required capital for the OKA plan. In addition, the market value of all our outstanding securities would probably have been adversely affected as well.

In the period 1976 through 1983, we would have been required to raise about $4.1 billion of new capital under the OKA plan. I believe that a downgrading to the BBB category in 1976 would have increased our overall cost of capital in this period by at least 50 basis points (0.50%). Thus, the increased cost on the full $4.1 billion of capital raised in the 1976 to 1983 period would have amounted to at least $20 million per year by 1983. Over the 1976-1983 period, the cumulative higher cost of capital would have amounted to at least $75 million. These costs have not been reflected in our analysis of the OKA construction plan.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Table 3

Annual Changes to PE Financing
Program Required by OKA
Construction Schedule
(Million $)

	Change In		
	Direct Costs	AFUDC	Total Change
1975	$43.8	$1.9	$45.7
1976	39.6	4.3	43.9
1977	49.8	9.1	58.9
1978	72.0	14.4	86.4
1979	100.6	22.7	123.3
1980	140.7	37.7	178.4
1981	157.5	63.1	230.6
1982	76.2	85.5	161.7
1983	(280.1)	82.5	(197.6)
1984	(407.6)	(256.9)	(664.5)
1985	(149.7)	(323.7)	(473.4)
Total	($147.2)	($259.4)	($406.6)

Table 4

Hypothetical Changes to Actual PE Financing Program
As a Result of OKA
Construction Schedule
(Million $)

	Debt						
	Mortgage	Debentures	STD	Credit Agreement	Preferred Stock	Common Stock	Total
1975	20.0		9.8			15.9	45.7
1976			17.6			26.3	43.9
1977	50.0		(15.3)			24.2	58.9
1978	75.0		11.4				86.4
1979		50.0	13.3			60.0	123.3
1980		100.0	20.9			57.5	178.4
1981		125.0	(9.2)		50.0	64.8	230.6
1982		100.0	(48.7)		20.0	90.4	161.7
1983	100.0		6.4	(200.0)		(104.0)	(197.6)
1984	(148.7)		(65.6)	(200.0)	(100.0)	(150.2)	(664.5)
1985	(141.0)		44.2	(150.0)		(226.6)	(473.4)
Total	(44.7)	375.0	(15.2)	(550.0)	(30.0)	(141.7)	(406.6)

2/15/86

PHILADELPHIA ELECTRIC COMPANY
LIMERICK I and COMMON
HYPOTHETICAL FINANCING CHANGES UNDER OKA CONSTRUCTION SCHEDULE
1975-1985

			Date Issued	Price or Rate
1975				
MB	$20.0 million	Size increase from $80 million to $100 million Due 2000	Aug. 6	11%
CMN	$15.9 million	Rights offering @ $12.25 1.3 million add'l shares	Sept. 17	$12.25/share
STD	$ 9.8 million	Balance = $9.8 million		7.9%
Amount Needed:	$45.7 million			
1976				
CMN	$26.3 million	1,500,000 add'l shares	Oct. 6	$17.50/share
STD	$17.6 million	Balance = $27.4 million		6.8%
Amount needed:	$43.9 million			

			Date Issued	Price or Rate
1977				
MB	$25.0 million	Size increase from $75 million to $100 million Due 2007	March 8	8.625%
MB	$25.0 million	Size increase from $75 million to $100 million Due 2003	July 6	8.625%
CMN	$24.2 million	1,200,000 add'l shares	Oct. 5	$20.125/share
STD	($15.3) million	Balance = $12.1 million		7.1%
Amount needed:	$58.9 million			
1978				
*MB	$75.0 million	New - Based on Moody's baa	Sept. 10	9.5%
STD	$11.4 million	Balance = $23.5 million		9.1%
Amount needed:	$86.4 million			
1979				
*DEB	$50.0 million	New - based on Moody's (10.5%) + 150 basis points	March 1	12.0%
*CMN	$60.0 million	4 million new shares based on 10/79 ESPP Price @$15.00	Oct. 15	$15.00/share
STD	$13.3 million	Balance = $36.8 million		12.7%
Amount needed:	$123.3 million			

* NEW ISSUE

			Date Issued	Price or Rate
1980				
*DEB	$100.0 million	New-based on Moody's baa (12.75%) + 150 basis points	July 1	14.25%
*CMN	$ 57.5 million	4 million new shares Based on ESPP Price of 8/80 @$14.375	Sept 2	$14.375/share
STD	$20.9 million	Balance = $57.7 million		15.3%
Amount needed:	$178.4 million			
1981				
*PFD	$ 50.0 million	Based on Moody's baa (14.8%)	Feb. 1	14.8%
CMN	$ 49.5 million	4 million add'l shares	April 2	$12.375/share
CMN	$ 15.3 million	1.2 million add'l shares	Sept 30	$12.75/share
*DEB	$125.0 million	New - based on Moody's baa (17.0%) + 150 basis points)	Dec. 1	18.5%
STD	$ (9.2)million	Balance = $ 48.5 million		18.9%
Amount needed:	$230.6 million			

* NEW ISSUE

			Date Issued	Price or Rate
1982				
PFD	$ 20.0 million	Size increase from $30 to $50 mill div. rate increase from $17.125 to $17.50	Feb 18	17.5%
CMN	$ 42.4 million	3 million add'l shares	April 6	$14.125/share
*DEB	$100.0 million	New - based on Moody's baa (17.1%) + 150 basis points)	July 1	18.6%
CMN	$ 48.0 million	3 million add'l shares	Oct. 6	$16.00/share
STD	($48.7) million	Balance = ($0.2) million		14.9%
Amount needed:	$161.7 million			
1983				
CMN	($104.0) million	Elimination of Common Stock issue 6.0 million shares	March 29	$17.40/share
*MB	$100.0 million	New - based on Moody's baa	March 29	11.25%
BOR	($200.0) million	Eliminate borrowing under $400 million domestic revolver	Nov. 16	11% - 12%
STD	$6.4 million	Balance = $6.2 million		10.8%
Amount needed:	($197.6) million			

* NEW ISSUE

1984			Date Issued	Price or Rate
PFD	($ 50.0) million	Eliminate 14.625% Preferred Stock	March 21	14.625%
CMN	($ 77.3) million	Elimination of Common Stock Issue 6 million shares	April 12	$12.875/share
*MB	$100.0 million	New - Based on Moody's baa (15.5%)	June 1	15.5%
CMN	($ 11.9) million	Elimination of Common Stock Issue 1 million shares-Continuous Offering	Aug. 1	$11.9/share
PC	($ 8.7) million	Eliminate Floating Rate Pollution Control Notes Due 2012	Sept. 28	Floating
CMN	($ 52.0) million	Elimination of Common Stock Issue 4 million shares	Oct. 4	$13.00/share
CMN	($ 9.0) million	Elimination of Common Stock Issue 612,900 shares-Continuous Offering	Nov 14	$14.7/share
PFD	($ 50.0) million	Eliminate $10 Depositary Preferred	Dec. 11	14.15%
BOR	($200.0) million	Eliminate net borrowing under Limerick Credit Agreement		
PC	($240.0) million	Eliminate Limerick Pollution Control Notes	Dec. 19	Variable @6.00 - 6.15%
STD	($65.6) million	Balance = ($59.4) million		12.0%
Amount needed:	($664.5) million			

* NEW ISSUE

1985			Date Issued	Price or Rate
MB	($ 50.0) million	Reduce 10.875% Mortgage Bonds Due 1995	Nov. 20	10.875%
MB	($ 50.0) million	Reduce 11.75% Mortgage Bonds Due 2014	Nov. 20	11.75%
CMN	($ 62.5) million	Elimination of Common Stock Issue 4 million shares	Nov. 14	$15.625/share
BOR	($150.0) million	Eliminate net borrowing under LCA	-	
PC	($41.0) million	Eliminate 10-1/2% Pollution Control Bonds	Nov. 11	10-1/2%
CMN	($53.4) million	Elimination of Common Stock Issue 3,387,000 shares of continuous offering	Jan. - Oct.	$15.77/share
CMN	($110.7) million	Elimination of Dividend Reinvestment Program 7.1 million shares	Jan. - Dec.	$15.59/share
STD	$ 44.2 million	Balance = ($15.2) million		9.5%
Amount needed:	($473.4) million			

* NEW ISSUE

Financial Division
2753K

Table 6

Comparison of Actual PECo Capital Structure
With Hypothetical OKA Financing Plan

	Debt Ratio - %		Preferred Ratio - %		Common Ratio - %		Average Number Common Stock - Shares		Cumulative Change
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	OKA STD
1975	51.8%	51.9%	13.7%	13.5%	34.5%	34.6%	58,135	58,154	$9.8
1976	51.5	51.2	14.0	13.7	34.5	35.1	65,605	67,249	27.4
1977	51.7	51.6	13.1	12.7	35.2	35.7	70,844	73,919	12.1
1978	52.0	52.7	13.6	13.0	34.4	34.3	75,391	79,391	23.5
1979	52.3	52.9	12.8	11.9	34.9	35.2	80,529	85,362	35.8
1980	51.3	52.2	13.2	12.1	35.5	35.8	87,302	96,535	57.7
1981	51.7	52.5	11.9	11.3	36.5	35.2	99,557	114,857	48.5
1982	51.1	51.8	11.1	10.7	37.8	37.6	115,480	136,580	(0.2)
1983	50.0	50.8	11.9	11.7	38.0	37.5	133,852	152,552	5.2
1984	51.8	51.8	11.4	10.9	36.8	37.3	151,804	163,261	(59.4)
1985	51.8	51.6	10.5	10.7	37.7	37.8	169,784	159,528	(15.2)

2820K

Table 7

Comparison of Actual PECo Financial Ratios
With Hypothetical OKA Financing Plan

	Earnings Per Share		AFUDC % Earnings		Mortgage Coverage		Preferred Coverage	
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical
1975	$1.86	$1.86	62.0%	53.2%	2.53 X	2.51 X	1.55 X	1.65 X
1975	1.91	1.91	61.8	63.8	2.48	2.47	1.63	1.67
1977	1.87	1.87	64.9	68.9	2.34	2.25	1.64	1.65
1978	1.87	1.87	64.4	71.0	2.35	2.14	1.59	1.57
1979	1.86	1.86	75.7	85.7	2.07	1.88	1.52	1.53
1980	2.00	2.00	84.3	95.9	2.25	2.05	1.58	1.57
1981	2.25	2.25	84.4	97.3	2.11	1.99	1.60	1.56
1982	2.39	2.39	76.5	91.5	2.42	2.35	1.71	1.67
1983	2.40	2.40	85.8	97.9	2.26	2.15	1.64	1.67
1984	2.70	2.70	86.5	22.2	2.55	4.46	1.75	1.77
1985	2.55	2.56	99.7	25.3	1.98	4.12	1.79	1.81

PECO STATEMENT NO. 3B

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

CORRECTED

REBUTTAL TESTIMONY OF

JOSEPH F. PAQUETTE, JR.

REVISED

FINANCIAL IMPACT OF

ADDITIONAL FINANCINGS

REQUIRED UNDER THE OKA

HYPOTHETICAL LIMERICK

CONSTRUCTION SCHEDULE

February, 1986

CORRECTED REBUTTAL TESTIMONY OF JOSEPH F. PAQUETTE, JR.

Q. Are you the same Joseph F. Paquette, Jr., who previously filed testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this correction to your rebuttal testimony?

A. This correction to my rebuttal testimony adjusts my previous testimony to be consistent with the OKA Limerick Unit No. 1 construction schedule. In reviewing my prior analysis, it was discovered that we had not properly reflected all aspects of the OCA's proposed schedule related cost disallowances. Specifically, we had failed to recognize the OCA's proposed adjustments for Bechtel and PECO indirects which it is alleged would not have been incurred had Limerick been completed in November 1983.

Revised Table 3 shows the yearly changes which the corrected OKA construction schedule would have produced in our financing program.

Q. Mr. Paquette, in making the above detailed adjustments, has it been necessary to change the hypothetical financings detailed in Table 5 of your rebuttal testimony?

A. Yes. Revised Table 4 shows an overall summary of the year-by-year changes to the Company's historic financing schedule which would have been necessary to meet the OKA construction schedule incorporating the adjustments previously described. Revised Table 5 shows the detail of each financing. Specific changes to Table 5 in my rebuttal testimony include:

<u>1975 to 1979 ($332.0 Million Required vs. $358.2 Million)</u>

A reduction of $26.2 million from the $358.2 million total requirement identified in my rebuttal testimony would be absorbed through short-term debt.

<u>1980 ($143.1 Million Required vs. $178.4 Million)</u>

The new $100 million debenture issue sold in July was reduced to $75 million. The additional $10.3 million reduction was absorbed through short-term debt.

<u>1981 ($178.2 Million Required vs. $230.6 Million)</u>

The new $125 million debenture issue sold in December was reduced to $75 million. The additional $2.4 million reduction was absorbed through short-term debt.

<u>1982 ($98.0 Million Required vs. $161.7 Million)</u>

The new $100 million debenture issue sold in July was eliminated. The increase in the connom stock offering in October was reduced to an additional one million shares in order to maintain capitalization ratios. Short-term debt was then increased by $68.3 million.

1983 ($240.7 Million Lower Requirement vs. $197.6 Million Lower)

The new $100 million mortgage bonds issue sold in March was reduced to $75 million. The additional $18.1 million reduction was absorbed through short-term debt.

1984 ($675.6 Million Lower Requirement vs. $664.5 Million Lower)

The new $100 million mortgage bond issue sold in June was increased to $125 million. Additionally, the Company's Dividend Reinvestment and Stock Purchase Plan was eliminated, reducing common issued by 6.885 million shares. Short-term debt was increased $58.1 million.

1985 ($473.4 Million Lower Requirement vs. $473.4 Million Lower)

The November issuance of 11.75% mortgage bonds was increased by $50 million to $250 million - reversing the previous $50 million reduction. Short-term debt was decreased by $50 million

Q. Please summarize the changes that the revised hypothetical OKA financing plan would have produced.

A. Revised Table 6 presents a summary of the capital structure that results from the hypothetical OKA financing plan for the period 1975 through 1985 as compared with the actual PE structure. As indicated on revised Table 6, the hypothetical OKA financing plan would have maintained the various capitalization ratios at a level very close to actual for every year in the study. In addition, our short-term position would have been increased by only $4.2 million through December 31, 1985. Revised Table 7 shows a comparison of the key financial ratios (earnings per share, AFUDC as a % of earnings, mortgage coverage ratio and preferred stock ratio) for a hypothetical and actual financing programs. While we programmed earnings per share under the hypothetical OKA plan to be identical to the actual earnings per share, the percentage of earnings represented by AFUDC increased significantly under the hypothetical plan in some years, resulting in a reduction in the quality of earnings. In addition, we would have experienced a lower mortgage coverage ratio during the period 1975 to 1982, inclusive, under the revised hypothetical OKA plan. Of particular concern is the period 1977 to 1981 when the OKA plan would have shown a serious decline in mortgage coverage, especially in 1979 when the ratio was only 1.89 times. I have calculated that approximately $179 million of additional revenue would have been required during the period 1975-83 to prevent this serious decline in mortgage coverage ratios under the OKA plan, in addition to the revenue needed to maintain earnings per share.

Q. Mr. Paquette, what are your conclusions regarding this study relating to the hypothetical OKA financing?

A. I believe that the revised hypothetical financing plan outlined is extremely optimistic in terms of the availability of capital and the cost of capital. In the period from 1973 to 1980, in particular, we were operating in a capital market environment which was extremely volatile and nervous. Even if we assume that it would have been possible to raise the required capital, it would probably have necessitated a significant increase in the cost of the capital and undoubtedly a downgrading of our security ratings, which would have further increased the costs of the OKA plan and resulted in higher rates for our customers.

Q. Mr. Paquette, are these conclusions expressed above with respect to your revised analysis, the same as the conclusions you reached based upon your original analysis?

A. Yes, they are. These revisions to the original analysis are not significant and do not change any of the conclusions stated in my rebuttal testimony.

Q. Does this conclude your corrected rebuttal testimony?

A. Yes, it does.

Table 3

Annual Changes to PE Financing
Program Required by OKA
Construction Schedule
(Million $)

	Change In		
	Direct Costs	AFUDC	Total Change
1975	$38.7	$3.8	$42.5
1976	34.1	10.0	44.1
1977	42.7	19.8	62.5
1978	62.2	14.1	76.3
1979	85.9	20.7	106.6
1980	111.1	32.0	143.1
1981	121.7	56.5	178.2
1982	23.2	74.8	98.0
1983	(280.7)	40.0	(240.7)
1984	(408.7)	(266.9)	(675.6)
1985	(149.7)	(323.7)	(473.4)
Total	($319.5)	($318.9)*	($638.4)

*Includes ($317.9) million associated with Limerick No. 1 and 100% of common plant.

Table 4

Hypothetical Changes to Actual PE Financing Program
As a Result of OKA
Construction Schedule
(Million $)

	Debt						
	Mortgage	Debentures	STD	Credit Agreement	Preferred Stock	Common Stock	Total
1975	20.0		6.6			15.9	42.5
1976			17.8			26.3	44.1
1977	50.0		(11.7)			24.2	62.5
1978	75.0		1.3				76.3
1979		50.0	(3.4)			60.0	106.6
1980		75.0	10.6			57.5	143.1
1981		75.0	(11.6)		50.0	64.8	178.2
1982			19.6		20.0	58.4	98.0
1983	75.0		(11.7)	(200.0)		(104.0)	(240.7)
1984	(123.7)		(7.5)	(200.0)	(100.0)	(244.4)	(675.6)
1985	(91.0)		(5.8)	(150.0)		(226.6)	(473.4)
Total	5.3	200.0	4.2	(550.0)	(30.0)	(267.9)	(638.4)

2/25/86

PHILADELPHIA ELECTRIC COMPANY
LIMERICK I and COMMON
HYPOTHETICAL FINANCING CHANGES UNDER OCA CONSTRUCTION SCHEDULE
1975-1985

			Date Issued	Price or Rate
1975				
MB	$20.0 million	Size increase from $80 million to $100 million Due 2000	Aug. 6	11%
CMN	$15.9 million	Rights offering @ $12.25 1.3 million add'l shares	Sept. 17	$12.25/share
STD	$ 6.6 million	Balance = $6.6 million		7.9%
Amount Needed:	$42.5 million			
1976				
CMN	$26.3 million	1,500,000 add'l shares	Oct. 6	$17.50/share
STD	$17.8 million	Balance = $24.4 million		6.8%
Amount needed:	$44.1 million			

			Date Issued	Price or Rate
1977				
MB	$25.0 million	Size increase from $75 million to $100 million Due 2007	March 8	8.625%
MB	$25.0 million	Size increase from $75 million to $100 million Due 2003	July 6	8.625%
CHN	$24.2 million	1,200,000 add'l shares	Oct. 5	$20.125/share
STD	($11.7) million	Balance = $12.7 million		7.1%
Amount needed:	$62.5 million			
1978				
*MB	$75.0 million	New - Based on Moody's bas	Sept. 10	9.5%
STD	1.3 million	Balance = $14.0 million		9.1%
Amount needed:	$76.3 million			
1979				
*DEB	$50.0 million	New - based on Moody's (10.5%) + 150 basis points	March 1	12.0%
*CHN	$60.0 million	4 million new shares based on 10/79 ESPP Price @$15.00	Oct. 15	$15.00/share
STD	(3.4) million	Balance = $10.6 million		12.7%
Amount needed:	$106.6 million			

* NEW ISSUE

			Date Issued	Price or Rate
1980				
*DEB	$ 75.0 million	New-based on Moody's baa (12.75%) + 150 basis points	July 1	14.25%
*CMN	$ 57.5 million	4 million new shares Based on ESPP Price of 8/80 @$14.375	Sept 2	$14.375/share
STD	$10.6 million	Balance = $21.2 million		15.3%
Amount needed:	$143.1 million			
1981				
*PFD	$ 50.0 million	Based on Moody's baa (14.8%)	Feb. 1	14.8%
CMN	$ 49.5 million	4 million add'l shares	April 2	$12.375/share
CMN	$ 15.3 million	1.2 million add'l shares	Sept 30	$12.75/share
*DEB	$ 75.0 million	New - based on Moody's baa (17.0%) + 150 basis points)	Dec. 1	18.5%
STD	$(11.6)million	Balance = $ 9.6 million		18.9%
Amount needed:	$178.2 million			

* NEW ISSUE

			Date Issued	Price or Rate
1982				
PFD	$ 20.0 million	Size increase from $30 to $50 mill div. rate increase from $17.125 to $17.50	Feb 18	17.5%
CMN	$ 42.4 million	3 million add'l shares	April 6	$14.125/share
CMN	$ 16.0 million	1 million add'l shares	Oct. 6	$16.00/share
STD	$19.6 million	Balance = $29.2 million		14.9%
Amount needed:	$98.0 million			
1983				
CMN	($104.0) million	Elimination of Common Stock issue 6.0 million shares	March 29	$17.40/share
*MB	$ 75.0 million	New - based on Moody's baa	March 29	11.25%
BOR	($200.0) million	Eliminate borrowing under $400 million domestic revolver	Nov. 16	11% - 12%
STD	($11.7) million	Balance = $17.5 million		10.8%
Amount needed:	($240.7) million			

* NEW ISSUE

1984			Date Issued	Price or Rate
PFD	($ 50.0) million	Eliminate 14.625% Preferred Stock	March 21	14.625%
CMN	($ 77.3) million	Elimination of Common Stock Issue 6 million shares	April 12	$12.875/share
*MB	$125.0 million	New - Based on Moody's baa (15.5%)	June 1	15.5%
CMN	($ 11.9) million	Elimination of Common Stock Issue 1 million shares-Continuous Offering	Aug. 1	$11.9/share
PC	($ 8.7) million	Eliminate Floating Rate Pollution Control Notes Due 2012	Sept. 28	Floating
CMN	($ 52.0) million	Elimination of Common Stock Issue 4 million shares	Oct. 4	$13.00/share
CMN	($ 9.0) million	Elimination of Common Stock Issue 612,900 shares-Continuous Offering	Nov 14	$14.7/share
PFD	($ 50.0) million	Eliminate $10 Depositary Preferred	Dec. 11	14.15%
BOR	($200.0) million	Eliminate net borrowing under Limerick Credit Agreement		
PC	($240.0) million	Eliminate Limerick Pollution Control Notes	Dec. 19	Variable @6.00 - 6.15%
	($94.2) million	Eliminate Dividend Reinvestment Program 6,885,000 shares		$13.68/Share
STD	($7.5) million	Balance = ($10.0) million		12.0%
Amount needed:	($675.6) million			

* NEW ISSUE

			Date Issued	Price or Rate
1985				
MB	($ 50.0) million	Reduce 10.875% Mortgage Bonds Due 1995	Nov. 20	10.875%
CMN	($ 62.5) million	Elimination of Common Stock Issue 4 million shares	Nov. 14	$15.625/share
BOR	($150.0) million	Eliminate net borrowing under LCA	–	
PC	($41.0) million	Eliminate 10-1/2% Pollution Control Bonds	Nov. 11	10-1/2%
CMN	($53.4) million	Elimination of Common Stock Issue 3,387,000 shares of continuous offering	Jan. - Oct.	$15.77/share
CMN	($110.7) million	Elimination of Dividend Reinvestment Program 7.1 million shares	Jan. - Dec.	$15.59/share
STD	$(5.8) million	Balance = ($4.2) million		9.5%
Amount needed:	($473.4) million			

* NEW ISSUE

Financial Division
2753K

Table 6

Comparison of Actual PECo Capital Structure
With Hypothetical OKA Financing Plan

	Debt Ratio - %		Preferred Ratio - %		Common Ratio - %		Average Number Common Stock - Shares		Cumulative Change
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	OKA STD
1975	51.8%	51.9%	13.7%	13.6%	34.5%	34.6%	58,135	58,154	$6.6
1976	51.5	51.2	14.0	13.7	34.6	35.1	65,605	67,249	24.4
1977	51.7	51.6	13.1	12.7	35.2	35.7	70,844	73,919	12.7
1978	52.0	52.7	13.6	13.0	34.4	34.3	75,391	79,391	14.0
1979	52.3	52.9	12.8	11.9	34.9	35.2	80,529	85,362	10.6
1980	51.3	52.0	13.2	12.1	35.5	35.9	87,302	96,635	21.2
1981	51.7	51.9	11.9	11.4	36.5	36.7	99,557	114,857	9.6
1982	51.1	50.7	11.1	11.0	37.8	38.3	116,480	136,109	29.2
1983	50.0	49.7	11.9	12.1	38.0	38.2	133,852	150,552	17.5
1984	51.8	51.6	11.4	11.3	36.8	37.1	151,804	157,818	10.0
1985	51.8	51.7	10.5	11.0	37.7	37.4	169,784	160,743	4.2

Table 7

Comparison of Actual PECo Financial Ratios
With Hypothetical OKA Financing Plan

	Earnings Per Share		AFUDC % Earnings		Mortgage Coverage		Preferred Coverage	
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical
1975	$1.86	$1.86	62.0%	64.9%	2.53 X	2.47 X	1.65 X	1.65 X
1976	1.91	1.91	61.8	68.2	2.48	2.38	1.65	1.67
1977	1.87	1.87	64.9	76.6	2.34	2.10	1.64	1.65
1978	1.87	1.87	64.4	70.8	2.35	2.14	1.59	1.57
1979	1.86	1.86	75.7	84.4	2.07	1.89	1.52	1.52
1980	2.00	2.00	84.3	92.9	2.26	2.09	1.58	1.57
1981	2.25	2.25	84.4	94.9	2.11	1.99	1.60	1.58
1982	2.39	2.39	76.5	88.6	2.42	2.33	1.71	1.73
1983	2.40	2.40	85.8	87.5	2.26	2.33	1.64	1.71
1984	2.70	2.70	86.6	20.6	2.55	4.31	1.75	1.79
1985	2.56	2.56	99.7	26.7	1.98	3.79	1.79	1.80

ORIGINAL

R-891364

PECO STATEMENT NO. 6

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DIRECT TESTIMONY

OF

THOMAS P. HILL, JR.

ACCOUNTING EXHIBITS,
SALE OF 400 MW OF CAPACITY AND ENERGY, PHASE-IN PLAN
LIMERICK 1 PRUDENCE DISALLOWANCE,
EFFECT OF DELAY DECISIONS,
UNCOLLECTIBLE ACCOUNTS, LIMERICK 1
DEFERRED COSTS, DAMAGED NUCLEAR FUEL

RECEIVED
JUL 21 1989
SECRETARYS OFFICE
Public Utility Commission

JULY 1989

DIRECT TESTIMONY OF THOMAS P. HILL, JR.

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

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

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

A. I am Manager of the Rate Division and Controller Designate of Philadelphia Electric Company (PECO or the Company).

Q. What is your educational background?

A. I graduated with honors from Lehigh University in 1970 with a B.S. in Industrial Engineering. I received my Master of Business Administration from Lehigh University in 1974. In 1986, I completed the Executive Development Program at Cornell University's Johnson Graduate School of Management.

Q. Please outline your experience with the Company?

A. Following my graduation from college in 1970, I joined the Company as an Engineer in the Rate Division. I held this position until 1978 when I was appointed Supervisor of Tariff and Special Projects within the Rate Division. In March 1982 I was appointed Assistant Manager, and in May 1986 I was appointed to my present position of Manager of Rate Division. In April 1989, I was appointed Controller Designate of the Company while concurrently holding the title of Manager of Rate Division.

Q. Mr. Hill, would you describe your responsibilities in your various assignments and outline your prior experience in rate proceedings?

A. Yes, I have prepared Appendix A to my testimony which describes my background and qualifications.

Q. **What is the purpose of your direct testimony in this proceeding?**

A. My testimony provides an overview of the Company's claim for additional revenue from customers, arising principally from the expected commercial operation of Limerick 2 in early 1990. I will present portions of the Company's accounting presentation and Commission rate case filing requirements, including:

<u>PECO Exhibit No. 1</u> - The Company's responses to regulations at 52 Pa.Code Sections 53.52 and 53.53.

<u>PECO Exhibit No. 3</u> - The Company's Statement of Reasons identifying the need for additional revenues and the components of our additional revenue requirements.

<u>PECO Exhibit No. 4</u> - The Company's response to Title 66 Pa.C.S. Section 1316(c) relating to advertising expenses in the historic and future test years.

<u>Exhibit TPH-1</u> - The historic test year Accounting Exhibit which responds to regulations and provides a comparison to our future test year claim.

<u>Exhibit TPH-2</u> - The future test year Accounting Exhibit which details the Company's claims in this proceeding.

Additionally, my testimony will support the basic accounting and financial statements in the Company's accounting exhibits, and variances between the historic and future test years not specifically addressed by other witnesses.

My testimony also will discuss several specific issues, including (1) the Company's decision to sell 400 MW of capacity and associated energy to other utilities for an intermediate term, (2) the Company's proposal to phase-in the proposed increase (3), the Company's position and claim relative to the Commission's disallowance of approximately $369 million in rate base for Limerick 1 at Docket R-850152, (4) the proper method to evaluate the effect on our customers of an alternative service date for Limerick 2, and (5) certain specific accounting adjustments relative to our claimed level of uncollectible accounts, recovery of deferred costs from the Limerick 1 rate proceeding at Docket R-850152, and recovery of the cost of fuel damaged during the second fuel cycle at Limerick 1.

Overview of the Rate Increase

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

A. The Company's claim reflects a net increase in Pennsylvania jurisdictional electric operating revenues of $548.6 million or 18.1% of total revenues. As explained in the Statement of Reasons (PECO Exhibit No. 3), this revenue increase is required (1) to permit the Company to recover the capital and operating costs of Limerick 2 offset by energy savings from this unit and an intermediate term sale of a portion of the Company's energy and capacity, (2) to reflect higher operating and maintenance expenses offset by substantially higher sales and lower capital costs, and (3) to allow the Company's common equity investors an opportunity to earn a reasonable return on their investment.

Q. Please explain the derivation of the net $548.6 million requested revenue increase.

A. The net increase is comprised of two components: (1) a gross rate increase of $691.0 million (22.8%) to reflect additional plant in service and increased operating expenses and (2) a $142.4 million rate decrease (4.7%) to reflect the reduction in energy costs associated with the operation of Limerick 2. The energy savings are reflected in this filing by a 4.586 mills/kWh reduction in the base rate cost of energy, including gross receipts tax. A corresponding reduction in the base cost of energy in the Company's Energy Cost Rate Factor ("ECRF") will be filed to become effective coincident with the effective date of Supplement No. 49. To the extent that actual energy savings from Limerick 2 are more or less than projected, this difference will be refunded or recouped in subsequent ECRF filings.

Q. Please explain the specific rate effect of Limerick 2.

A. A principal reason for this rate filing is to reflect the capital and operating costs and associated energy savings for Limerick 2. Table 1 to this testimony details these costs and savings. As set forth therein, the net rate effect of Limerick 2 is $550.0 million, consisting of an $812.0 million increase in capital and operating costs, offset by a $119.5 million reduction associated with the intermediate term sale of energy and capacity, and a reduction of $142.4 million in anticipated energy savings. As this table demonstrates, the net revenue requirement for Limerick 2 accounts essentially for the entire rate request. All other elements of cost of service produce about a $1 million reduction in total revenue requirements.

Sale of Capacity

Q. Please explain the reduction in revenue requirements associated with the 400 MW intermediate term sale of energy and capacity.

A. The Company has adjusted rate base and test year expenses to remove investment and expenses associated with a 400 MW intermediate term sale of energy and capacity to other utilities. The rate base and expense adjustments for this sale are included in the Company's pro forma revenues and expenses and are detailed on pages C-10 and D-17 of Exhibits TPH-1 and TPH-2. In general, these adjustments were calculated by first determining the ratio of megawatts sold (400 MW) to total installed capacity, including Limerick 2 (8,766 MW), and then applying that ratio (400 MW/8,766 MW) to relevant rate base and expense accounts. Table 2 attached to my testimony derives the total $119,445,000 reduction in revenue requirements associated with the sale for the twelve months ending March 31, 1990.

Q. Please define what you describe as an intermediate term sale.

A. An intermediate term sale, as I use the phrase in this testimony, refers to a contract term in excess of one year but not extending beyond a four year period.

Q. Mr. Hill, please describe the basis for the Company's sale of 400 MW of capacity and associated energy.

A. Commercial operation of Limerick 2 is forecasted for February 1, 1990. With the addition of Limerick 2, the Company had planned to retire four oil fired units which had reached the end of their normal service lives. These units, Schuylkill No. 1, Delaware 7 and 8 and Cromby 2 provide 623 MW of installed capacity to the PECO system. Several PJM members, who are currently short on reserve capacity, expressed an interest in purchasing capacity and energy from PECO. Based on these requests the Company determined that it was beneficial to our customers to negotiate the sale of a portion of our system capacity and energy rather than retire these units. The terms and conditions for sale were determined through "arms length" negotiations to maximize the level of revenue from the sale. The Company evaluated the prospective sale price based on the average revenue requirements of our production and transmission system, including Limerick 2 and all existing capacity. This embedded cost methodology is generally the same cost analysis that the Company would utilize in reviewing an incremental sale to a customer or use to develop rate structures or rate designs.

The Company's ability to sell 400 MW of capacity and energy and still meet our reliability criteria is discussed more fully in the testimony of G. H. Haak.

Q. Has the Company reached agreement with any PJM members on the terms of sale.

A. Yes, in part. We have signed a letter of agreement with Atlantic Electric for the sale of 200 MW and associated average system energy commencing in June 1990 and running through June 1994. In addition, we have reached tentative agreement with another PJM member company for the sale of 150 MW of energy and capacity for a two year period also beginning June 1990. The sale of the remaining 50 MW and the 150 MW in years 3 and 4 is still under active negotiation with other companies.

Q. Is the Company committing to remove the entire 400 MW of capacity and associated energy for ratemaking purposes in this proceeding even if the sales have not been made by the end of the case?

A. Yes. We will commit to reduce average system revenue requirements to reflect the sale of 400 MW as shown in our accounting presentation.

Q. Do Pennsylvania jurisdictional customers benefit from the sale of this energy and capacity?

A. Yes. Without these sales and the adjustments to our claimed revenue requirements, our rate request would increase by as much as $119.5 million.

Q. Mr. Hill does the Company expect the revenue received from these sales to exceed the allocated revenue requirements removed by your adjustment in this filing?

A. No, it does not. As I have stated the expected revenue from the sale is based upon negotiations with the PJM member companies. PECo has sought to maximize revenues and the buyers have sought to minimize their expenses. The net result of our negotiations has been an agreed upon level of revenue which is less than PECo's average system cost. The difference between revenue and the costs associated with these transactions will not be charged to customers.

Q. Does the Company intend to seek additional rate increases associated with the 400 MW of capacity and associated energy after the expiration of the 4-year period?

A. The Company will not claim any additional revenues in this proceeding. If the 400 MW of capacity and associated energy is required to serve customers after the 4-year period, the

Company would file for such relief in a future base rate filing. As stated in our Statement of Reasons (PECO Exhibit 3), the Company does not expect to file a future base rate increase within the next four years.

<u>Phase-In</u>

Q. Mr. Hill, please describe how the Company proposes to phase-in the net $548.6 million rate increase.

A. The Company proposes to phase-in the rate increase through a series of annual five percent (5%) increases in base rate revenues sufficient to recover the total increase allowed by the Commission and providing for a carrying charge on deferred revenues during the phase-in period.

Q. What is the proposed time frame for the phase-in plan?

A. Based upon the assumption that the Commission allows the full rate increase requested, the phase-in plan proposed by the Company spans a 10 year period, the maximum allowed by current accounting standards. The first annual increase of 5% is effective in April 1990, which assumes full suspension of the Company's request. Three additional 5% increases follow beginning in April 1991, April 1992 and April 1993. A final increase step of 1.9% takes effect in April 1994 and remains in effect until April 2000 at which time rates would drop to the requested level of increase. The reduction in rates takes place after the Company has recovered the revenue increase including all deferrals and the associated carrying charges on the deferrals.

Q. Mr. Hill, what level of carrying charge is the Company requesting on revenues deferred under the phase-in proposal?

A. The phase-in uses the Company's claimed after tax rate of return, which is 9.50%. Should the Commission establish an overall net-of-tax fair rate of return of less than or greater than 9.50%, then the phase-in should be adjusted accordingly.

Q. Is the Company under any accounting restrictions in establishing its proposed phase-in plan.

A. Yes, the Financial Accounting Standards Board adopted Statement of Financial Accounting Standards (SFAS) No. 92 in August 1987. In order to comply with generally accepted accounting principles for current recognition of revenue to be billed in the future, the Company's phase-in plan must conform to the guidelines of SFAS No. 92. Failure to meet these requirements would disqualify the phase-in plan for financial reporting purposes. PECo witness D. G. Farling presents testimony in this proceeding (PECO St. 21) describing the specific requirements of SFAS No. 92 (pp. 11-13) and the critical importance of establishing a qualified phase-in plan (pp. 13-15). Mr. Farling has also determined that our phase-in is a qualified plan (PECO St. 21, pp. 15-16).

Q. Mr. Hill, isn't the Company's current proposed phase-in plan different from that proposal adopted in the Limerick 1 case at Docket R-850152?

A. Yes. The Company's phase-in plan for Limerick 1 was proposed to and adopted by the Commission before the passage of SFAS 92. The Limerick 1 plan was shorter (a six-year plan) with three equal annual increases of about 4.8% followed by a fourth 4.8% increase that remained in effect for three years to recover all deferred revenue from the first two years of the plan. The Company did not request, and the Commission did not provide for, a return on deferred revenues. With the adoption of SFAS 92 in August of 1987, 14 months after our rate order at Docket R-850152, the Company was required to write off approximately $48 million, after taxes, as a result of not recovering carrying charges on the deferred revenue.

In order to comply with SFAS 92 and recognizing that the Commission has approved a return on deferred revenue in the recent Pennsylvania Power Company and Duquesne Light Company rate proceedings, the Company is seeking carrying charges on deferred revenues as an integral part of its phase-in plan.

Q. If the Commission reduces the Company's total rate request, what would be the effect on the phase-in plan?

A. Any reduction in the overall rate increase should reduce the required number of five percent increases and proportionately reduce the phase-in period. For example, if the Commission were to grant only 80% of the Company's total requested increase, the phase-in period would be reduced to 8 years (80% of 10 years) and the necessity of about one 5% annual increase would be eliminated. The Company would recalculate the number of 5% annual increase steps and the final increase necessary to provide for the total increase, recovery of deferred revenue and a return on all deferrals, and submit these calculations with the compliance filing.

Q. Why has the Company selected a 5% annual increase?

A. The Company's use of 5% is based on the expected rate of inflation during the phase-in period. Five percent is a reasonable average of most forecasts of the Consumer Price Index (CPI) and the Gross National Product Implicit Price Deflator (GNP deflator). The Commission recognized the importance of maintaining the relationship of electric price increases and the rate of inflation at R-850152. The Company believes its proposal is consistent with the concept underlying the Commission's position.

Other considerations include 1) conformity with the 4.8% annual increases for the Limerick 1 phase-in plan, 2) PECo's desire to remain competitive with alternative energy sources, and 3) the ability to provide reasonable and timely recovery of this increase and to reflect cash flow requirements.

Limerick 1 Rate Base Disallowance

Q. Mr. Hill, at Docket R-850152 the Commission disallowed approximately $369 million in Limerick 1 investment based on the conclusion that the Company imprudently delayed the completion of this unit in 1976 and 1978. Does the Company seek to include this investment in rate base in this filing?

A. The Company was required to write off this investment in conformance with SFAS 90 (Accounting of Abandonments and Disallowances of Plant Costs). The $369 million investment therefore is not included in the Company's books of account and rate base as shown in Exhibits TPH-1 and TPH-2.

The Company continues to believe that the decisions to delay Limerick 1 in 1976 and 1978 were reasonable and prudent, and that the Commission's calculation of the disallowance was in error. Extensive discussion of the Company's position is found in the Testimony of PECo Witnesses J. S. Kemper (PECO St. 1, pp. 49-62), J. J. Clarey (PECO St. 2, pp. 6-9), C. H. Rush (PECO St. 4, pp. 18-33), M. W. Rimerman (PECO St. 5), W. A. Abrams (PECO St. 7, pp. 28-41) and R. T. McWhinney (PECO St. 8, pp. 39-52). The Commonwealth Court has reversed the Commission and the Commonwealth Court's decision has been appealed to the Pennsylvania Supreme Court.

Table 3, appended to my testimony, derives the revenue requirement associated with the Commission's rate base disallowance as valued at the end of the future test year. While this revenue requirement is not specifically shown in the accounting exhibits, the Company is not waiving its right to recover this revenue requirement. The Commission adjustment is reflected in our exhibits merely for ease and consistency of presentation. The Company specifically requests that the Commission reconsider and reverse its prior decision and allow the Company a full return on its Limerick 1 investment.

As shown on Table 3, the test year revenue requirement associated with the inclusion of the $369 million in rate base is $57.6 million. The Company recognizes that if the Commission were to reverse its conclusion as respects this disallowance, the Company cannot expect a revenue level in this proceeding in excess of the total gross revenue increaase request of $691.0 million or a net $548.6 million. As such, I have prepared Tables 4 and 5 which recast the Company's A-1 and A-2 sheets from Exhibit TPH-2 to include in rate base the $369 million of plant disallowed by the Commission. As Table 4 indicates, with the full revenue increase requested, our return would fall from 11.77% to 11.44% and our return on equity would drop from 14.0% to 13.1%. Alternatively, the $57.6 million revenue requirement can be used to offset any Commission adjustments to the Company's rate base, revenue and expense claims.

<u>Limerick 2 Schedule</u>

Q. **In the Commission decision at Docket R-850152, it was found that Limerick 1 could have been completed some 27 months earlier. Is that your understanding of the Commission finding?**

A. Yes. The Commission found that Limerick 1 could reach commercial operation in November 1983 rather than February

1986 if the Company had not delayed construction of that unit in 1976 and 1978. Given that finding the Commission then calculated that the capital cost of Limerick 1 would have been $368.9 million less with the earlier service date. The Company disagrees. Limerick 1 could not have been completed substantially before February 1986, and if it could have been completed earlier, it would have been more expensive. In addition, the Commission's adjustment is fundamentally miscalculated and overstated.

Q. Mr. Hill, assuming that the Commission's conclusion that Limerick 1 could have been completed 27 months sooner were correct, what effect would this conclusion have as to Limerick 2?

A. The Commission's Order at Docket No. I-80100341 required the Company to suspend construction of Limerick 2 until Limerick 1 achieved commercial operation. If Limerick 1 achieved commercial operation in November 1983 as opposed to February 1986, the Commission might have permitted the Company to resume construction of Limerick 2 earlier, although this is not entirely clear. Before permitting construction to restart the Commission conducted an extensive investigation of the need for and cost of Limerick 2 and the Company's financial ability to complete this unit. It is far from clear that such an investigation could have been completed by November 1983.

If the Company could have restarted Limerick 2 construction in November 1983, then Limerick 2 may have been completed sooner, although this is not a question that can be answered without substantial analysis to review any major differences between restarting construction in 1983 vs. 1986.

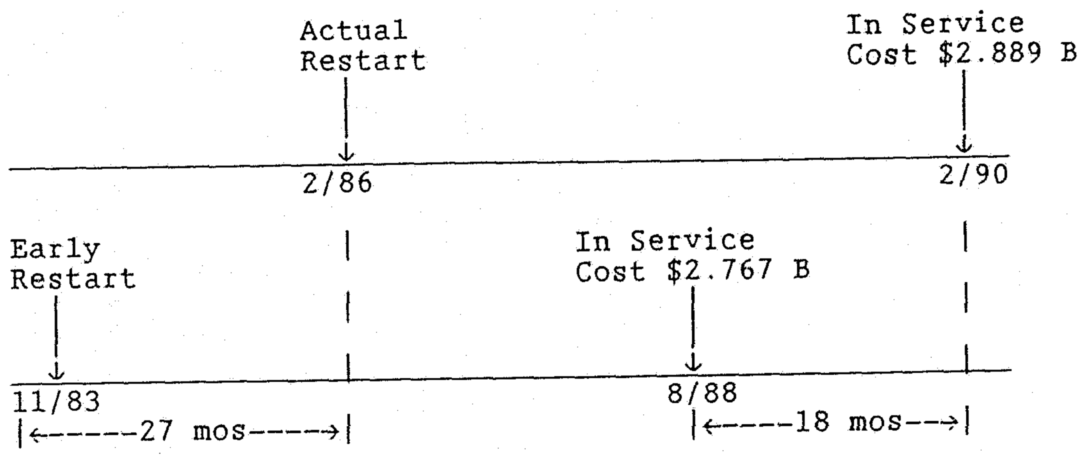
Q. Has the Company performed such an analysis?

A. Yes. In order to evaluate an alternative completion date PECO witness R. J. Barretta (PECO St. 9) has constructed a hypothetical construction schedule for Limerick 2 assuming the restart of construction commenced in November 1983 rather than February 1986, or 27 months sooner, consistent with the Commission's finding in the Limerick 1 case.

Q. What were the results of Mr. Barretta's analysis?

A. Working off the as-built cost and schedule for Limerick 2 which shows completed construction in February 1990 at a cost of $2.889 billion, Mr. Barretta has determined that with an earlier restart in November 1983, Limerick 2 would have been completed in August 1988 at the earliest at a cost of $2.767 billion (PECO St. 9, p. 19). As Mr. Barretta discusses, this very optimistic schedule results in a capital cost savings of $122 million and an 18 month earlier in-service date for the unit. Figure 1 depicts the alternative service schedules.

Figure 1
Cost and Schedule Comparison
Actual versus Early Restart



Q. Does this $122 million capital cost differential fairly represent the cost to PECO customer of the later completion of Limerick 2?

A. Absolutely not. In order to quantify the cost of a change in the service date of a generating unit it is necessary to consider all effects on customers. If Limerick 2 had been completed and placed in service 18 months earlier, the Company would have sought a substantial revenue increase at that time to include its investment in Limerick 2 in base rates. Thus, customers would have begun paying for Limerick 2 eighteen months earlier than under the actual schedule. Similarly, if Limerick 2 went into service 18 months sooner, it presumably would be retired 18 months sooner, and it is reasonable to assume that an additional base load facility, equal in capacity, would have to be placed in service to fill the gap left by the earlier retirement of Limerick 2. In addition, in order to complete Limerick 2 18 months earlier, the Company would have to raise more capital earlier. Since the cost of capital obviously changes over time, raising additional capital in different time periods can have a substantial cost impact which must be reflected in any complete assessment of the costs and benefits of plant completion at a particular point in time.

To determine the effect on customers of an earlier completion date on a complete and consistent basis one must consider all of these cost components on a present value basis and not just the construction cost differential.

Q. **Have you prepared such an analysis as part of your testimony?**

A. Yes. I have prepared a complete anlaysis of all differential costs and benefits associated with the completion of Limerick 2 in August 1988 vs. February 1990. This analysis shows that the total present worth of customer revenue requirements associated with a February 1990 Limerick 2 commercial operation date is $4.791 billion. The comparable total present worth of customer revenue requirements of completion in August 1988 is $5.339 billion. The difference between these two figures, i.e., $547.7 million is the net present worth <u>benefit</u> to our customers of completing Limerick 2 in February 1990 vs. August 1988. Spreading this benefit over the entire service life of the unit (39 years) yields an annual revenue requirement savings to customers of $53.6 million per year.

Q. Mr. Hill, how can one conclude that customers benefited from the later completion of Limerick 2 when this delay increased the capital cost of the plant by $122 million?

A. Simply stated, the $122 million capital cost savings do not offset the cost to customers of paying for Limerick 2 in rates sooner and replacing the unit sooner at the end of its life.

Q. Can you provide an example to demonstrate why one cannot simply compare the capital cost of Limerick at two points in time to determine the full effect on customers?

A. Yes I can. The principal flaw in comparing nominal dollar figures at different points in time is that such an analysis fails to reflect the time value of money. The benefit of receiving $1,000 today is obviously not the same as the benefit of receiving $1,000 five years from today. One who receives $1,000 today can invest the money and earn a return on it during the intervening five-year period. Similarly, it is not appropriate to simply look at a hypothetical $122 million difference in construction cost of Limerick 2 in 1988 vs. 1990.

Another example would be a decision to purchase an automobile in 1988 vs. the same model in 1990. A simple subtraction of the two costs does not provide a full cost/benefit analysis of the earlier purchase. A decision to buy the earlier and presumably less expensive car would have required earlier payment and earlier replacement. Later purchase would require payment of a higher cost, later replacement and some reflection of transportation cost in the interim period (1988-1990). My analysis of Limerick 2 completion in August 1988 and February 1990 simply reflects these additional factors. My analysis shows that on a present worth basis the cost savings of $122 million from earlier completion are not enough to offset the additional cost to our customers of paying for Limerick 2 sooner and replacing it sooner at the end of its life.

Q. Please describe the specifics of your analysis in more detail.

A. To examine the difference in revenue requirements associated with different in-service dates of Limerick 2, I employed a model which evaluates the net present worth of revenue requirements of the two alternatives. This method assembles all Limerick 2 related costs to serve customers, including capital carrying charges, operating costs and fuel over a sufficient time period to eliminate the bias of time differentiated expenditures.

This analysis is best understood by viewing it in three time periods: (1) the period of August 1988 to February 1990, when Limerick 2 is in service under the earlier schedule and still under construction in the as-built schedule; (2) February 1990 through August 2027, when Limerick 2 is operating under both schedules; (3) August 2027 to February 2029 when Limerick 2 is retired under the earlier schedule and still in service under the as-built schedule.

In period 1, i.e., August 1988 through February 1990, customers incur the cost of Limerick 2 under the earlier schedule in the form of capital carrying charges (return, taxes and depreciation) and operating costs of the plant. These additional revenue requirements are partially offset through fuel savings generated from the Limerick 2's operation.

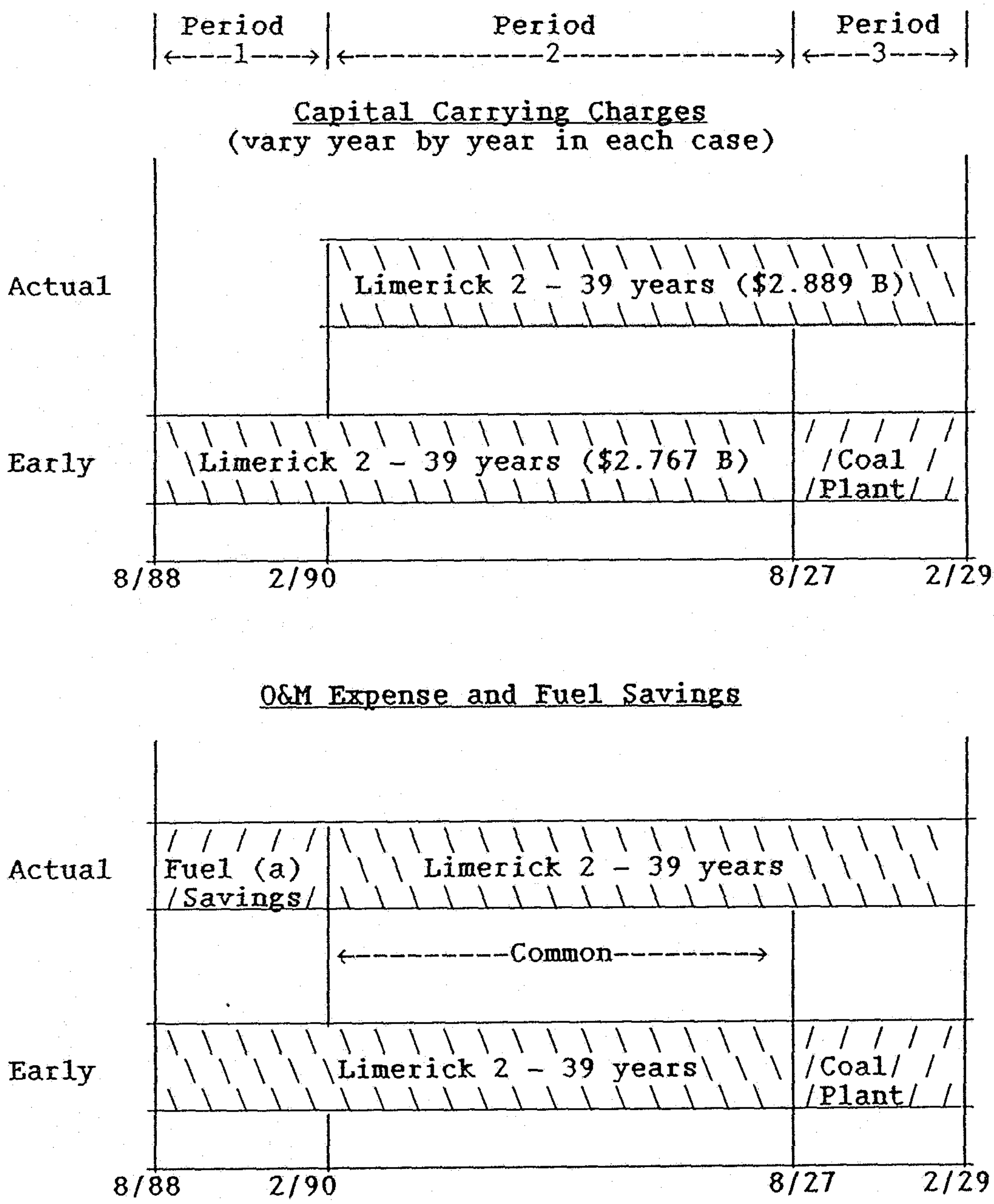
In period 2, i.e., February 1990 to August 2027, Limerick is operating in both cases and therefore the operating costs and associated fuel savings are essentially the same and need not be separately analyzed. These are common costs which will not impact the analysis. Capital carrying charges are different in the cases during this period since the initial plant costs are different and the pattern of cost recovery is different. These variations are reflected in my analysis.

In period 3, i.e. August 2027 through February 2029, Limerick 2 is retired in the earlier schedule and must be replaced. For this period I have utilized a coal plant replacement and added the levelized carrying charges and operation and maintenance expense for the coal plant and fuel cost differential for the 18 month "tail end" effect.

The time lines shown in figure 2 depict these three periods of analysis for both capital carrying charges and operating and maintenance expense and fuel savings.

Figure 2

Carrying Charges and Expense
for Actual and Early Completion



(a) Fuel Savings in Early Completion
Or Replacement Power in Actual Completion

Q. Are there any other elements in your revenue requirement analysis?

A. Yes, my analysis also reflects the incremental costs necessary to finance the completion of Limerick 2 on the earlier schedule. Under the actual schedule, Limerick 2 was completed during the February 1986 - February 1990 time frame. Under the earlier completion schedule construction was completed during November 1983 - August 1988. In order to complete Limerick 2 on the earlier schedule the Company would have had to raise additional capital during the 1983-87 period, and less capital in 1988-1990. Since the cost of capital was generally higher during the 1983-88 period than in 1986-1990 period, the Company clearly would have incurred additional financing costs under the earlier schedule. PECo witness J. F. Brennan has evaluated the two capital requirement schedules, actual and early completion, and provided an assessment of the net additional financing costs for early completion (PECO St. 23, pp. 45-52).

Based upon Mr. Barretta's alternative early restart schedules, $750 million of additional capital financings would have been required during 1983 through 1987. The cost of these incremental financings for the early schedule are shown on Table 6.

Table 6 first compares the difference in cash flow of the actual construction schedule (February 1990 commercial operation date) with the early schedule (August 1988 commercial operation date). The next step compares the average embedded cost of capital to the incremental financings described by Mr. Brennan and summarized on Table 7. I have reexpressed these cost differentials on a pre-tax, or revenue requirement basis, and applied the difference in cost rates to the difference in cash flows. This provides the year by year change in total revenue requirements, or cost to customers, caused by the change in financing requirements.

With no further changes in financing schedules, the cumulative revenue requirement for incremental financing cost would remain at that level until the issues were refinanced or expired at maturity. As a conservative assumption in my analysis, I have assumed refinancing occurs immediately after the commercial operation of Limerick 2 under the actual construction schedule. This assumption acts to minimize the revenue requirements in the earlier completion case.

Q. **What is the next step in your analysis?**

A. All costs in the case of early completion and actual completion must be discounted to a base period in order to evaluate the total revenue requirements on a fair and consistent basis. I have discounted to 1990 to coincide with the end of our future test year.

Q. **What does your analysis show?**

A. The results of my analysis show that early completion of Limerick 2 in August 1988 as compared to actual completion would have provided <u>no net benefit to our customers</u> as measured in a revenue requirement analysis for the life cycle of Limerick 2. The total present worth benefit to customers of actual completion at February 1990 is $548 million. Distributing this benefit over the service life of the unit (39 years) yields an annual revenue requirement savings or cost savings to customers of about $53 million per year ($547 million x capital recovery factor).

Figure 3 summarizes the various components of my revenue requirement analysis which are detailed on Table 8 appended to my testimony.

Figure 3
Alternate Limerick 2 Completion
Present Worth of Revenue Requirements
(Million $)

	Actual	Early	Benefit/(Cost) Actual to Completion
Limerick 2			
Carrying Charges	$4,791.7	$5,210.0	$418.3
Period 1 O&M Expense	-	87.0	87.0
Period 1 Fuel Savings	-	(210.7)	(210.7)
Incremental Financing Cost	-	122.8	122.8
Sub-Total	$4,791.7	$5,209.1	$417.4
Coal Plant (Period 3)			
Carrying Charges	-	$94.5	$94.5
O&M Expense	-	4.4	4.4
Fuel Cost Increase	-	31.4	31.4
Sub-Total	-	$130.3	$130.3
Total	$4,791.7	$5,339.4	$547.7

As shown, the net benefit to our customers of actual completion in February 1990 over August 1988 is so overwhelming that one need not even consider the impact of the additional financing costs or the tail-end effects of the coal replacement.

Excluding these items, which I still believe are appropriate for a complete analysis, shows that actual completion in February 1990 is still advantageous to customers by $294.6 million expressed in present worth of revenue requirements. Further, from reviewing the table above one can see that the results are <u>not</u> highly sensitive to long range projections of fuel savings or operating and maintenance expense since these long range estimates impact only the tail end effects which have been severely discounted.

Q. Mr. Hill are there any other customer impacts of early completion of Limerick 2?

A. Yes. My analysis as presented only looks at Limerick 2 investment. In addition to Limerick 2, the Company is requesting the inclusion of the remaining 50% of common plant in rate base which was deferred by the Commission pending completion of the second unit. Our customers will begin supporting the revenue requirements for this investment only after commercial operation of the second unit. With earlier completion of Limerick 2, for example August 1988, customers would have begun paying for essentially the same common plant earlier. Assuming no cost differences for common plant with early or late completion of Unit 2, since this plant was completed with the first Limerick unit, customers have received the time value of money benefit for the 18 month difference between service dates (August 1988 and February 1990). The additional present worth revenue requirement savings to customers associated with the remaining 50% of common plant totals $236 million (See Table 9). This is an additional dollar saving to customers in excess of those savings previously discussed.

Description of Accounting Data

Q. Mr. Hill, please describe PECO Exhibit No. 1.

A. This exhibit provides the Company's responses to the Commission filing regulations at 52 Pa. Code Sections 53.52 and 53.53. Responsive answers are contained therein or direct the reader to various testimony and exhibits submitted with this filing. I am responsible for the assembly and submission of all data contained in this exhibit, but many responses were prepared by other witnesses and are so identified.

Q. Please describe PECO Exhibit No. 4.

A. This Exhibit provides the Company's response to the statutory requirements for governing the submission of information and materials on advertising expenses claimed in a base rate proceeding. The Exhibit includes an extensive list of the types of advertising prepared, distributed and presented that are the basis for these expenditures.

Q. Please describe the accounting data which you have prepared to support Supplement No. 49 to Tariff Electric--Pa. PUC No. 26.

A. In support of Supplement No. 49, we have provided Exhibit TPH-1, based on an historic test year ended March 31, 1989, which reflects data from the Company's actual books of account. We have also provided Exhibit TPH-2 based on the future test year ended March 31, 1990, which reflects data drawn from the Company's 1989/1990 budget. PECO witness J. R. Reifsnyder discusses in greater detail the Company's budget process (PECO St. 13, pp. 4-10) which provides the major source of information necessary to construct Exhibit TPH-2.

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

A. Yes, I am.

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

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

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

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

A. Exhibit TPH-2 contains four sections:

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

<u>Section B</u> contains basic accounting information from the Company's records;

<u>Section C</u> contains data relating to the Measure of Value, and

<u>Section D</u> shows details of adjustments to Revenues and Expenses.

Q. Please explain your development of the Company's income available for return under present rates for the test year ended March 31, 1990.

A. As indicated on page A-1 of Exhibit TPH-2, our pro forma electric operating income under present rates for the March 31, 1990 test year is $739,034,000. This represents a rate of return of 7.64% on the claimed original cost Measure of Value of

$9,668,761,000.

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

A. Page A-1 presents the pro forma income available for return and the rate of return at the present and proposed rate levels. Actual (Exhibit TPH-1) or budgeted (Exhibit TPH-2) revenue, expenses, and income were taken directly from the Electric Operating Income Statement shown on page B-8 of the respective Exhibits and were adjusted for the items shown on page A-3 to derive the proforma income at present rates. The proforma income at present rates was then adjusted to reflect the higher rates of Supplement No. 49 to derive the operating income available for return under the proposed rates.

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

Also, the Company's measure of value has been reduced by certain items. The Company has reduced rate base by all accumulated deferred income taxes associated with accelerated amortization of property and liberalized depreciation on plant in service. The allocated rate base associated with the intermediate term sale of energy and capacity is also eliminated. In addition, Customer Deposits and Customer Advances, which are supplied by ratepayers, are eliminated from the rate base calculation. Finally, the Miscellaneous Deferred Credit associated with the Salem 2 Tax Benefit Transfer is eliminated.

Page A-3 lists the 25 adjustments to income for return. The first 24 adjustments increase income by approximately $51.0 million in the March 31, 1990 test year. The details of each adjustment are included in Section D. The last adjustment, shown on page D-25, reflects reductions in energy expenses resulting from the inclusion of Limerick 2 in rates to serve Pennsylvania jurisdictional customers. This adjustment reduces revenue requirements to customers but has no effect on operating income for PECo because energy expenses are reconciled through the Energy Cost Rate Factor (ECRF).

Page A-4 indicates the effect on income for return of Supplement No. 49 and highlights the associated fuel savings from the inclusion of Limerick 2 in rates.

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

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

A. Section B information in Exhibit TPH-1 was taken directly from the Company's actual accounting records. The data in Exhibit TPH-2 for the specific 12-month period ended March 31, 1990 is taken from the Company's 1989/1990 budget.

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

A. Pages B-1 and B-2 of Exhibit TPH-2 represent the Company's estimated balance sheet at March 31, 1990.

Pages B-3 through B-6 show the original cost by plant accounts at test year end of the Company's electric plant and common utility plant, a portion of which is allocated to electric service by the allocation factor developed on page B-16. PECo witness W. H. Smith explains the Company's accounting procedures used to develop plant in service (PECO St. 17, pp. 4-6).

Page B-7 shows the consolidated income statement for the Company and its subsidiaries.

Page B-8 presents the operating income statement for the Company's electric operations.

Pages B-9 through B-13 show by primary accounts the expense items for electric operations. I am responsible for preparation of these schedules and for the explanation of historic versus test year claimed expense levels, except in the case of production plant expenditures explained by PECO witness J. J. Carroll (PECO St. 16, pp. 2-14), depreciation, nuclear decommissioning and spent nuclear fuel disposal, explained by PECO witness A. B. Cohn (PECO St. 15, pp. 3-7, 25-27), and taxes explained by PECo witness S. R. Xander (PECO St. 18).

Pages B-14 and B-15 show the computation of federal income tax and the development of electric operations share of the rate base adjustment for accumulated deferred taxes. Mr. Xander (PECO St. 18) is available to explain and support the Company's claimed income tax expense.

Page B-16 develops the factors for allocating common utility plant to electric operations. The allocation of the common plant in each Exhibit was made on the basis of the estimated plant investment, revenue, and customers at March 30, 1990 for each type of service.

Page B-17 shows the calculation of the effective income tax rate which was developed by Mr. Xander.

Pages B-18 and B-19 list the Company's long-term debt and preferred stock outstanding and develops the associated embedded cost for each test year period. Mr. Brennan will explain the development of the Company's embedded cost of long-term debt and preferred stock (PECO St. 23, pp. 14-16).

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

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

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

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

Page C-1 contains a general description of the Company's claimed measure of value. Mr. Smith provides support for original cost (PECO St. 17). This page also provides a description of annual and accrued depreciation and amortization calculations used in the determination of measure of value. Mr. Cohn's testimony (PECO St. 15, pp. 3-7) explains the basis of these annual depreciation calculations and Mr. Smith's testimony (PECO St. 17, pp. 6-9) explains the development of the book depreciation reserve.

Pages C-2 and C-3 summarize by plant groupings the utility plant in service for each test year showing both the original cost and book depreciation reserve. These pages also summarize the annual provision for depreciation. Mr. Smith explains the Company's accounting procedures and the FERC and PaPUC audits which assure that all property contained within these accounts is in fact in service (PECO St. 17, pp. 9-11). Mr. Cohn provides support for the annual provision for depreciation (PECO St. 15, pp. 3-7).

Page C-4 provides the terminal dates for production plant utilized under the remaining life method of depreciation. PECO witness G. H. Haak is available to discuss the establishment of these dates (PECO St. 10).

Page C-5 develops the rate base deduction associated with the Salem 2 Tax Benefit Transfer. This schedule will be discussed by Mr. Xander (PECO St. 18, pp. 7-9).

Page C-6 lists land held for future use. This schedule will be explained by Mr. Cohn (PECO St. 15, p. 8).

Page C-7 displays the Company's claim for electric operations materials and supplies. This schedule will also be explained by Mr. Cohn (PECO St. 15, pp. 8-11).

Pages C-8, C-8a and C-8b reflect the Company's investment in nuclear fuel stored at Limerick Station. Mr. Carroll will discuss these adjustments (PECO St. 16, pp. 3-4).

Page C-8c increases the rate base to provide for a return on the cost of the undamaged fuel bundles at Limerick 1. As explained in my discussion of page D-11, the total estimated amount of the fuel that can be recovered and reused is $26,300,000. This amount, representing nuclear fuel inventory for Limerick 1 or Limerick 2 is added to the Company's measure of value on page A-2.

Page C-9 details the levels and requirements for cash working capital at the historic and future test year ends. This schedule will be explained by Mr. Cohn (PECO St. 15, pp. 12-17).

Page C-10 reflects the elimination of allocated rate base as a result of the intermediate term sale of 400 MW and associated energy. The Company's rate base for electric operations is reduced by $377,821,000 to reflect eliminations for plant, reserve, fuel inventory and accumulated deferred taxes that are allocated to this 400 MW portion of the system as determined by the calculations shown on Table 10. The applicable adjustments for operating expense for this sale are shown on page D-17.

Page C-11 provides for a return on the unrecovered costs for Limerick 1 associated with the Declaratory Order at Docket No. P-840514. The components of the unrecovered costs and the annual recovery of this cost are explained in the discussion of page D-22 in my testimony. The net unrecovered cost of $133,250,000 is added to the Company's measure of value. This addition to claimed rate base is principally (approximately 92%) accrued carrying charges incurred between the commercial operation date for Limerick 1 on February 1, 1986 and the inclusion in rates by Commission Order effective June 27, 1986. Such carrying charges, like AFUDC, are properly capitalized and recovered over the expected life of the assets.

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

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

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

A. There are several steps involved in review of the future test year claim. The first step compares budgeted revenues and expenses in the future test year to those in the historic test year and preceding years. We next review any significant changes with the responsible individuals to determine reasons for the changes and whether amounts should be included in the test year, excluded from the test year or whether any amortizations or normalization adjustments are necessary. This review is performed under my direction to assure that claimed revenue and expense levels are "normal" and therefore a proper claim is made for (1) transmission and distribution expenses, (2) customer accounts, (3) customers service and informational expense (4) sales expense, and (5) administrative and general expenses. Mr. Carroll performs a similar review for production expenses, Mr. Xander is responsible for tax expense and Mr. Cohn for depreciation expense. Finally, the accounting presentation is reviewed with appropriate Company personnel to confirm that proforma claims reflect expected operations during the period new rates will be effective.

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

A. The adjustment on <u>Page D-1</u> proposes to recover the state taxes covered by the State Tax Adjustment Clause (STAC) in base rates. Mr. Xander will support this adjustment (PECO St. 18, pp. 5-6).

Page D-2 adjusts revenues to reflect the elimination from test year income of the Temporary Negative Surcharge Adjustment imposed by the Commission.

Page D-3 adjusts revenues, expenses, and operating income to annualize to test year end levels for (1) customers added during the test year, and (2) the growth/decline in usage of existing customers.

Page D-4 eliminates from the test year data the revenues and expenses covered by the Energy Cost Rate Factor (ECRF). Mr. Cohn will describe and support adjustments D-2, D-3 and D-4 (PECO St. 15, pp. 18-21).

Page D-5 presents the Company's annualization of wage rates, pensions, benefits and number of employees for each of the test years. Mr. Reifsnyder discusses this adjustment (PECO St. 13, pp.14-16).

Page D-6 adjusts annual depreciation expense to reflect plant in service at the end of the test year. Mr. Cohn is responsible for this adjustment (PECO St. 15, pp. 21-22).

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

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

Page D-9 shows the calculation of the adjustment to income taxes resulting from the allocation of proforma interest charges based on the Company's rate base at the end of the test year. Mr. Xander is available to discuss pages D-7 through D-9 in greater detail (PECO St. 18, pp. 3-4).

Page D-10 adjusts nuclear and fossil plant production operating and maintenance expenses to reflect a normalized level of expenses for ratemaking purposes. Mr. Carroll will discuss these expense adjustments (PECO St. 16, pp. 5-13).

Page D-11 reflects recovery for the amortization of certain damaged fuel bundles for Limerick 1.

Q. Mr. Hill, what is the origin of the Limerick 1 damaged fuel?

A. During the second fuel cycle for Limerick 1, the Company experienced fuel failures as a result of Crud Induced Localized Corrosion (CILC). The second refueling outage was scheduled in order to replace 224 of the 764 bundles which comprise the reactor core. Review of the remaining core (540 bundles) resulted in replacement with 296 new bundles, a rebuild of 48 bundles from the initial core, reload of 44 bundles from reload 1 and reinsertion of 152 bundles from those previously discharged at reload 1.

On June 14, 1989, the Company updated the Commission and all parties of record at Dockets I-880082 on the status of the investigation of the fuel failures. As that report indicates, the Company has not inspected all of the prematurely discharged fuel removed from Limerick 1 to determine which fuel can be reconstituted for use in future reloads. The fuel that was prematurely discharged from the reactor has a residual value of

$52.6 million. Based upon samples of the fuel taken to date, the Company currently estimates that approximately 50% of that fuel can be recovered for future use. As additional information becomes available during the course of the proceeding, the Company will update the proposed accounting claim.

Q. **What is the Company's proposal to recover the cost of the damaged fuel and the disposition of the undamaged portion of the discharged bundles?**

A. The Company proposes to recover the damaged fuel (estimated at $26,300,000) over a four year period which would result in an increase in expense of $6,575,000 and a decrease in income for return of $3,971,000. For the undamaged fuel, represented by the remaining 50% of unamortized value, the Company proposes to add this investment to rate base since this fuel represents inventory for future refueling.

Q. **Mr. Hill, please continue with your discussion of the Accounting Exhibits.**

A. <u>Page D-12</u> shows the adjustment of book expenses to reflect the amortization of certain expenses provided for in prior rate proceedings and new items being claimed in this proceeding. Mr. Cohn will discuss this adjustment (PECO St. 15, p. 22).

<u>Page D-13</u> eliminates expenses in the Company's test year budget associated with the Commission's final Order at Docket No. C-78080459. Mr. Cohn will discuss this adjustment (PECO St. 15, pp. 23-24).

Page D-14 shows the adjustment to recognize changes in Federal Social Security Tax Laws. Mr. Xander is available to explain this adjustment (PECO St. 18).

Page D-15 shows the adjustment for the cost of decommissioning the Company's nuclear units at Peach Bottom, Salem and Limerick. Mr. Cohn (PECO St. 15, pp. 25-26) and PECo witness N. B. McLeod (PECO St. 22) will explain this adjustment and the Company's nuclear decommissioning analysis.

Page D-16 shows the adjustment to normalize spent fuel disposal expense in the Company's test year operating expenses. Mr. Cohn (PECO St. 15, pp. 26-27) and Mr. Carroll (PECO St. 16, p. 13) discuss this adjustment.

Page D-17 reflects the elimination of allocated expenses and taxes as a result of the 400 MW intermediate term sale of capacity and energy. Expenses including book depreciation, production and transmission expenses, administrative and general expenses and ad valorum taxes are reduced by $53,759,000 while income and deferred taxes are increased by $20,703,000, for the 12 months ending March 31, 1990, to reflect the allocated expenses and taxes due to this sale as detailed on Table 10. This adjustment results in an increase in income for return of $33,056,000 for the twelve months ending March 31, 1990. I note that the above effects on income and rate base were based on preliminary costs and as such will be revised in the Company's compliance filing to reflect the Company's final accounting exhibit and any subsequent Commission ordered adjustments.

Page D-18 reflects the full year effect of the operating and maintenance expenses, pensions and benefits, insurance expense and payroll taxes associated with Limerick 2. The non-fuel production, operation and maintenance expenses, pensions and benefits, insurance expense and payroll taxes for Limerick 2 were deferred for budget purposes. Consequently, this adjustment is required in order to reflect the proper level of test year expenses for Limerick 2. The Limerick 2 pensions, benefits and payroll taxes of $2,716,000 are based on labor additives for pensions, benefits and social security taxes applied to the estimated Limerick 2 labor expense. The incremental insurance expense for the second unit of $1,920,000 is the full year effect of the property, liability and replacement power coverages that were deferred for budget purposes. This expense represents the incremental increase for insurance expense at Limerick Station. Mr. Carroll will provide a detailed explanation of the operating and maintenance expense adjustment on this page (PECO St. 16, pp. 13-14). The total adjustment results in an increase to expense of $37,122,000 representing the total incremental operating cost for this unit.

Page D-19 adjusts income to reflect a system average rate of return from Conowingo Power Company (COPCo) and interdepartmental sales. The Company's cost of service study RAC-1 shows that the current rate of return from COPCo and the interdepartmental sales is lower than the overall average Company rate of return sought in this case. This adjustment increases the Company's income for return by $11,344,000. Since this adjustment is based on the Pennsylvania jurisdictional return level, it should be adjusted to reflect the revenue level granted by the Commission in its final order. I would note that the additional revenues imputed through this adjustment currently yield an overall rate of return of 12.59% which is in excess of the Company's claimed overall return of 11.77% (Exhibit RAC-1, p. 6). This return will be adjusted to the overall return in our final accounting exhibit.

Page D-20 reflects a full-year's amortization of utilized investment tax credit on qualifying plant placed in service during the test year. The effect of the adjustment is to place the ITC amortization on a year-end basis. Mr. Xander explains this adjustment (PECO St. 18, p. 5).

Page D-21 provides for an increase to the budgeted uncollectible accounts expense level.

Q. Mr. Hill, your adjustment on page D-21 suggests an increase to expense of $21,554,000 over that level budgeted in the future test year. Please explain the reasoning behind this substantial adjustment.

A. The uncollectible accounts estimated for the budget period of $23,914,000 severely understates our bad debt experience. Our existing accounting practices fail to reflect that a substantial percentage of customers currently under Special Payment Agreements (SPAs) do not have the financial resources necessary to pay for the service they utilize. At the close of business for 1988, our independent auditors required that we transfer $38 million of Accounts Receivable (Account 142) to Miscellaneous

Deferred Debits (Account 186) in recognition that these "assets" are not a current receivable from customers and in fact a substantial portion represents doubtful accounts due to the inordinately long repayment schedules. Further, the value of these accounts even if recovered have such little current value when discounted to present day that they lack worth as an asset. Our auditors have permitted the Company to carry these amounts under the presumption that the Company seek and receive regulatory approval to recover these amounts in the next rate case. Failure to receive such approval will result in an immediate write off of that portion representing doubtful accounts.

The Company therefore proposes a 6 year amortization of that portion of SPAs with repayment periods of four years or more. Accounts over four years were identified as doubtful accounts since this group of accounts represent approximately 26,000 customers who are currently in, or are expected to qualify for, our Customer Assistance Program (CAP). CAP customers have demonstrated, a partial or total inability to pay as measured by a review of each customer's verified financial resources. Since these customers do not have the financial resources to meet full payment, it is inappropriate to carry these SPAs as a receivable.

Likewise this same group of customers will not pay for all total current service taken. Those customers who qualify for CAP are required to meet several criteria including control of usage and payment of amounts equal to their demonstrated ability to pay. An analysis of the existing 5,006 CAP customers indicates that only 28.4% of their total bills are recoverable. This represents an inability to pay or forgiveness factor of 71.6%. Proper accounting dictates that the portion of current billings which are not expected to be recovered should be written off as they are billed.

A final adjustment to the uncollectible accounts claim is necessary to increase writeoffs for the higher level of revenue claimed in this case. This adjustment is based upon our total requested increase in revenue.

Q. Please continue with your discussion of the mechanics of the D-21 adjustment.

A. SPAs in excess of 4 year repayment schedules total $29,044,000 based upon the latest available data. I have attached as Table 12 to my testimony a summary of the Special Payment Agreement accounts status. The $29,044,000 is obtained by adding the balances in column 4 for the over 48 months through the over 300 months categories. Also provided on this table is the following information which is required for this adjustment: 1) repayment schedule - column 1; 2) total SPAs customers - column 2; 3) current months bill - column 3; 4) total SPAs balances - column 4.

The second part of this adjustment normalizes uncollectible accounts expense to reflect the expected level of customers (26,000) in the CAP program. The total current bills for customers with SPAs over 48 months, total $23,532,000 ($1,961,000 per month, from Table 12, column 3). Applying the

71.6% forgiveness factor yields a total uncollectible accounts expense for these customers of $16,850,000. The amount currently included in uncollectible accounts expense for these customers is $6,451,000 as shown on Table 13. The difference of $10,399,000 in uncollectibles is the additional amount required to derive a normal amount for prospective rates.

The final part of this adjustment increases uncollectible accounts to reflect the rate increase requested in this filing.

Q. **Please continue with your discussion of the D Section of the Accounting Exhibits.**

A. Page D-22 provides for the recovery of Limerick 1 costs incurred between its commercial operation and rate recognition. These costs were deferred pursuant to the Commission's final Order at Docket No. P-840514. The costs to be recovered include: $122,365,000 for carrying charges; $38,926,000 for non-fuel operation and maintenance expenses, depreciation and associated taxes; and $24,122,000 as a credit for fuel savings net of deferred taxes. The total net unrecovered cost of $137,169,000 is amortized over the period encompassing the expected rate effective date of this proceeding until the terminal date of Limerick Unit 1 (35 years) for an annual amortization of $3,919,000. The unamortized net unrecovered cost is also shown on page C-11.

Page D-23 incorporates the proceeds of the sale of the leased combustion turbines. Mr. Cohn will discuss this adjustment (PECO St. 15, p. 27).

Page D-24 reflects the effect of the IRS settlement of the Salem 2 Tax Benefit Transfer. Mr. Xander will discuss this adjustment (PECO St. 18, pp. 7-9).

Page D-25 adjusts the Company's energy costs to reflect the savings anticipated from the operation of Limerick 2. Specifically, the Company has reduced the cost of energy reflected in base rates by 4.586 mills per kilowatt-hour to reflect energy savings anticipated from the operation of Limerick 2. This net effect is summarized on pages A-4 and A-5 of Company Exhibit TPH-2. Mr. Carroll will explain the derivation of the reduction calculated on page D-25 (PECO ST. 16, pp. 14-16).

Q. Does that complete your testimony at this time?
A. Yes.

Limerick 2 and Common Revenue Requirements (a)
(Thousand $)

Exhibit TPH-2 Reference				
	Capital Costs (Lim 2 + 50% Common)			
C-2	Utility Plant in Service	$3,902,127		
C-2	Book Reserve	(84,898)		
C-7	Materials and Supplies	13,135		
C-8	Nuclear Fuel in Rate Base	65,748		
B-15	Accumulated Def. Taxes A/C Liberalized on Plant and Nuclear Fuel	(160,569)		
	Total Measure of Value	$3,735,543 x 16.46% (b)		$614,870
D-6	Book Depreciation $105,762/[(1-T) x (1-GRT)] (c)			$183,192
D-7a	Tax Depreciation $208,453 x T = $82,568/[(1-T)x(1-GRT)] (c)			(143,017)
D-8a	Excess Tax Depreciation $155,212 x FT = $52,772/[(1-T)x(1-GRT)] (c)			91,407
	Total Revenue Requirements for Capital			$746,452
	Incremental Operating Costs			
D-10a	Outage Expenses		$15,134	
D-15	Decommissioning Cost		4,364	
D-16	Spent Fuel Cost		6,007	
D-18	Operating and Maintenance Costs		37,122	
	Total Operating Cost		62,627	
	Gross Receipts Tax		2,882	
	Total Operating Cost			$65,509
	Total Gross Revenue Requirement			$811,961
C-10,D-17	Less: Intermediate Term Sale of Energy and Capacity			
	From C-10 $377,821 x 16.46% (a)		62,189	
	From D-17 $33,056/[(1-T)x(1-GRT)] (c)		57,256	
				($119,445)
D-25	Less: Fuel Savings			(142,438)
	Net Revenue Requirement			$550,078

(a) By Commission Order at R-850152 50% of Common plant was not included in rate base with the first Limerick Unit in accordance with Pennsylvania regulatory policy. 100% of Common plant was included in plant in service to conform with FERC accounting requirements.

(b) Rate of Return Component

	Capitalization	Cost	Wtd. Cost	Rev Req Factor
Debt	54.3	10.54	5.72	5.72
Preferred	9.3	10.19	0.95/ (1-T)	1.57
Common Equity	36.4	14.00	5.10/ (1-T)	8.45
	100.0			15.74/(1-GRT)=16.46%

(c) T = Effective Tax Rate @ 39.61% (B-17)
GRT = Gross Receipts Tax Rate @ 4.4% (A-4)
FT = Statutory Federal Tax Rate @ 34% (B-17)

Table 2

Revenue Requirement Reduction Associated with the Intermediate Term Sale of Energy and Capacity (Thousand $)

O&M Expenses and Taxes (Page D-17 of Exhibit TPH-2)			
Production and Transmission	$29,901		
Administrative and General	5,864		
Ad Valorum Taxes	3,649		
	$39,414		
Gross Receipts Tax (GRT) (a)	1,814		
Total Revenue Reduction		($41,228)	
Book Depreciation $14,345/[(1-T) x (1-GRT)] (a)		($24,847)	
Tax Depreciation ($14,345 + $9,589) x T / [(1-T) x (1-GRT)] (a)		16,421	
Excess Tax Depreciation $4,389 / [(1-T) x (1-GRT)] (a)		(7,602)	
Total Revenue Reduction-Expenses			($57,256)
Measure of Value (Page C-10 of Exhibit TPH-2)			
Plant in Service	$483,980		
Book Reserve	(83,944)		
	$400,036		
Plus: Materials & Supplies - Fuel	10,983		
Less: Acc. Deferred Taxes	(33,198)		
	$377,821 x 16.46% (b) = $62,189		
Total Revenue Reduction - Measure of Value			($62,189)
Total Revenue Reduction			($119,445)

(a) T = Effective Tax Rate @ 39.61% (B-17)
GRT = Gross Receipts Tax @ 4.4% (A-4)

(b) See Table 1, Footnote (b)

Revenue Requirements for the
$368.9 Million Prudency Disallowance
of Limerick 1
12 Months Ending March 31, 1990
(Thousand $)

Depreciation and ITC

Book Depreciation $10,386 / [(1-T) x (1-GRT)] (a)		$17,990
Tax Depreciation $23,130 x T = $9,162 / [(1-T) x (1-GRT)] (a)		(15,870)
Excess Tax Depreciation $16,951 x FT = 5,763 / [(1-T) x (1-GRT)] (a)		9,982
ITC Amortization ($485)/[(1-T) x (1-GRT)] (a)		(840)
Total Revenue Requirements for Depreciation and ITC		$11,262
Measure of Value		
Plant in Service	$368,900	
Book Reserve	(41,064)	
Accumulated Deferred Taxes - Federal	(46,281)	
Total Revenue Requirement for Measure of Value	$281,555 x 16.46% (a) =	$46,344
Total Revenue Requirement		$57,606

(a) T = Effective Tax Rate @ 39.61% (B-17)
GRT = Gross Receipts Tax Rate @ 4.4% (A-4)
FT = Statutory Federal Tax Rate @ 34% (B-17)

(b) From Table 1, Footnote (b)

Philadelphia Electric Company - Electric Operations
INCOME AVAILABLE FOR RETURN
ADJUSTED TO ELIMINATE THE LIMERICK 1
PRUDENCE DISALLOWANCE
12 Months Ended March 31, 1990
(Thousand $)

	Actual (B-8)	Adjustments (A-3)	Proforma Pres. Rates	Addl. Revs. (A-4)	Proforma Proposed Rates
Operating Revenue	2,901,785	235,759	3,137,544	548,640	3,686,184
Operating Expenses					
Operating and Maintenance Exp.	1,534,415	159,585	1,694,000	(136,164)	1,557,836
Depn. & Amort. (Incl. salvage)	257,497	101,951 (a)	359,448		359,448
Provision for Taxes					
Taxes Other Than Income	217,945	8,035	225,980	24,133	250,113
Income Taxes	101,063	(44,850)(b)	56,213	261,692	317,905
Provision for Deferred Taxes	161,464	(47,802)(c)	113,662		113,662
Income Taxes Def.-Other	(77,833)	13,302	(64,531)		(64,531)
ITC Adjustment-(net)	19,180	(5,323)(d)	13,857		13,857
Total Taxes	421,819	(76,638)	345,181	285,825	631,006
Total Operating Expenses	2,213,731	184,898	2,398,629	149,661	2,548,290
Operating Income Avail. for Return	688,054	50,861	738,915	398,979	1,137,894
Original Cost Measure of Value (from Table 5)			9,950,316		9,950,316
Return on Original Cost			7.43		11.44

Rate of Return Components

	Ratio	Cost	Wtd. Cost
Debt (B-18a)	0.543	10.54	5.72
Preferred (B-19)	0.093	10.19	0.95
Common Equity	0.364	13.10	4.77
			11.44

(a) Includes $10,386 for Limerick 1 prudence disallowance from Table 3.
(b) Includes ($9,162) reduction due to tax depreciation and ($6,383) reduction due to proforma interest charges on year-end plant for Limerick 1 prudence disallowance from Table 3.
(c) Includes $5,763 for Limerick 1 prudence disallowance from Table 3.
(d) Includes ($485) for Limerick 1 prudence disallowance from Table 3.

Philadelphia Electric Company - Electric Operations
MEASURE OF VALUE ADJUSTED TO
ELIMINATE THE
LIMERICK 1 PRUDENCE DISALLOWANCE
AT MARCH 31, 1990
(Thousand $)

	Reference	Original Cost	Less: Intermediate Term Sale of of Energy and Capacity (Page C-10)	Adjusted Original Cost to page A-1
Utility Plant in Service				
Electric	C-2	$12,918,437 (a)		
Allocated Common	C-2	144,225		
Total O.C. Plant in Service		$13,062,662 (a)	$483,980	$12,578,682
Less: Book Reserve on Plant in Service	C-2	2,502,780 (b)	83,944	2,418,836
		$10,559,882	$400,036	$10,159,846
Plus: Land Held for Future Use	C-6	0		0
Materials and Supplies	C-7	$142,523	$1,194	$141,329
Nuclear Fuel in Rate Base	C-8	214,522	9,789	204,733
Cash Working Capital	C-9	64,852		64,852
Limerick 1 Decl. Order Adj.	C-11	133,250		133,250
Total Additions		$555,147	$10,983	$544,164
Less: Accumulated Deferred Inc. Taxes				
Accelerated Amortization	B-2	$1,396		$1,396
Liberalized Depreciation	B-15	773,819 (c)	$33,198	740,621
Customer Deposits	B-2	9,590		9,590
Customer Advances	B-2	200		200
Salem 2 Tax Benefit Trans. Credit	C-5	1,887		1,887
Total Deductions		$786,892	$33,198	$753,694
Measure of Value		$10,328,137	$377,821	$9,950,316

(a) Includes $368,900 for Limerick 1 Prudence Disallowance from Table 3
(b) Includes $41,064 for Limerick 1 Prudence Disallowance from Table 3
(c) Includes $46,281 for Limerick 1 Prudence Disallowance from Table 3

Table 6

Yearly Revenue Requirements
For the Cost of Incremental Financing
(Thousand $)

Year	Cash Flow (a) Actual (1)	Early (2)	Difference (3)=(1)-(2)	Embedded Capital AFUDC (c) (4)	Incremental Capital (New Issues) (5) See Table 7	Incremental Cost (6)-(5)-(4)	Pre-Tax Incremental Cost (7)=(6)/(1-T)(b)	Revenue Requirement (8)=(7)x(3)	Cumulative Revenue Requirement (9)=Sum(8)	Revenue Requirement For Year (10)=(9)-½x(8)
1983	$108,666	$128,371	$19,705	9.3%	11.085%	1.785%	3.693%	$728	$728	$364
1984	139,619	425,572	285,953	9.4	11.192	1.792	3.708	10,603	11,331	6,029
1985	119,142	441,671	322,529	9.5	10.474	0.974	1.993	6,428	17,759	14,546
1986	343,824	425,313	81,489	9.55 (d)	9.313	(0.237)	(0.485)	(395)	17,364	17,563
1987	487,314	532,583	45,269	9.5	9.383	(.117)	(.212)	(96)	17,268	17,317
1988	492,479	253,292	(239,187)	9.5	10.125	0.625	1.035	(2,476)	14,792	16,031
1989	543,208	0	(543,208)	9.5	10.153	0.653	1.081	(5,872)	8,920	11,856
1990	94,399	0	(94,399)	9.5	9.811	0.311	0.515	(487)	8,433	8,677
Total	$2,328,651	$2,206,802	($121,849)					$9,373		$92,383

(a) From the Direct Testimony of R. J. Barretta

(b) T = Composite Tax Rate, See Table 7 column 8

(c) Historic AFUDC Rates

(d) Arithmetic Average of AFUDC Rates in Effect in 1986

*Prior Year

TABLE 6

Table 7

Incremental Capital Financing Cost
1983–1990
(Thousand $)

	Capitalization Ratios (a)			Capital Costs (a)					
	Debt (1)	Preferred Stock (2)	Common Equity (3)	Debt (4)	Preferred Stock (5)	Common Equity (6)	Weighted Cost(b) (7)	T (c) (8)	Weighted After Tax Cost (d) (9)
1983	50.0%	12.0%	38.0%	13.67%	13.70%	16.15%	14.616%	51.67%	11.085%
1984	52.4	11.3	36.3	14.41	14.87	16.15	15.094	51.67	11.192
1985	53.7	10.1	36.2	11.60	13.53	16.75	13.659	51.13	10.474
1986	51.3	10.4	38.3	10.57	9.75	14.75	12.086	51.13	9.313
1987	54.7	10.0	35.3	10.54	10.08	14.75	11.980	45.05	9.383
1988	50.0	12.0	38.0	10.58	11.05	14.75	12.221	39.61	10.125
1989	50.0	12.0	38.0	10.69	11.00	14.75	12.270	39.61	10.153
1990	50.0	12.0	38.0	10.50	11.00	14.00	11.891	39.61	9.811

(a) 1983–1987
Per Testimony of Mr. J. F. Brennan, Schedule 22, page 1 of 12
1988–1990 Represent the Company's target capitalization ratios

(b) (7)=[(1)x(4)]+[(2)x(5)]+[(3)x(6)]

(c) Composite effective state and federal income tax rate

(d) (9)=(7)-[(8)x(1)x(4)]

Table 7

Limerick 2 Construction Schedule Study
Analysis Done on Plant-year Basis
Discount Rate = 9.50%

YEAR	Carrying Charges Actual	Carrying Charges Early	Fuel Savings Actual	Fuel Savings Early	O & M Expense Actual	O & M Expense Early	Incremental Financing Costs	Net Annual Cost Difference $ Absolute	Net Annual Cost Difference $ PV (1990)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(1-2+3-4 +5-6-7)	(9)=PV(8)
1983	0	0	0	0	0	0	364	(364)	(687)
1984	0	0	0	0	0	0	6,029	(6,029)	(10,393)
1985	0	0	0	0	0	0	14,546	(14,546)	(22,898)
1986	0	0	0	0	0	0	17,563	(17,563)	(25,250)
1987	0	0	0	0	0	0	17,317	(17,317)	(22,737)
1988	0	228,565	0	(38,869)	0	21,058	16,031	(226,784)	(271,920)
1989	0	540,082	0	(118,671)	0	52,256	11,856	(485,523)	(531,647)
1990	527,719	520,395	0	(34,123)	0	4,572	8,677	28,197	28,197
1991	556,633	502,175					0	54,458	49,733
1992	537,258	484,610					0	52,648	43,909
1993	519,216	466,730					0	52,486	39,976
1994	501,023	448,643					0	52,380	36,434
1995	482,484	430,555					0	51,929	32,987
1996	463,916	412,467					0	51,450	29,847
1997	445,347	394,379					0	50,967	27,002
1998	426,777	382,209					0	44,569	21,563
1999	408,209	375,812					0	32,397	14,315
2000	402,516	365,902					0	36,614	14,774
2001	392,534	355,993					0	36,541	13,466
2002	382,055	346,085					0	35,971	12,105
2003	371,576	336,176					0	35,400	10,880
2004	361,095	326,266					0	34,829	9,776
2005	350,617	316,356					0	34,261	8,782
2006	340,138	306,447					0	33,691	7,887
2007	329,660	296,538					0	33,122	7,081
2008	319,179	286,628					0	32,552	6,355
2009	308,701	276,719					0	31,983	5,702
2010	298,221	266,810					0	31,411	5,114
2011	287,741	256,901					0	30,840	4,586
2012	277,262	246,991					0	30,271	4,111
2013	266,784	237,081					0	29,703	3,684
2014	256,305	227,172					0	29,133	3,299
2015	245,824	217,263					0	28,561	2,954
2016	235,345	207,353					0	27,992	2,644
2017	224,867	197,444					0	27,424	2,366
2018	214,388	187,535					0	26,853	2,115
2019	203,909	177,626					0	26,283	1,891
2020	193,429	167,717					0	25,712	1,689
2021	182,951	157,807					0	25,144	1,509
2022	172,472	147,896					0	24,576	1,347
2023	161,992	137,987					0	24,005	1,201
2024	151,513	128,079					0	23,434	1,071
2025	141,034	118,170					0	22,864	954
2026	130,555	108,260					0	22,296	850
2027	120,075	867,733	(80,763)			35,550	0	(863,970)	(30,073)
2028	109,597	1,939,086	(861,597)			89,637	0	(2,780,723)	(88,394)
2029	9,060	161,591	(41,667)			7,843	0	(202,040)	(5,865)
$ PV	4,791,695	(5,304,467)	(31,409)	210,673	0	(91,356)	(122,845)	(3,341,913)	(547,709)

Limerick 2 CC: (5,210,013)
Coal Stn. CC: (94,454)

Early Limerick 2 O&M: (87,041)
Incremental Coal Stn. O&M: (4,315)

Table 8

Limerick 2 Benefit Study
Analysis Done on Plant-year Basis: Common Plant Only
Discount Rate = 9.50%

YEAR	Carrying Charges Actual		Early	Net Annual Cost Difference $ Absolute	$ PV (1990)
1983	$ 0	$	0	$ 0	$ 0
1984	$ 0	$	0	$ 0	$ 0
1985	$ 0	$	0	$ 0	$ 0
1986	$ 0	$	0	$ 0	$ 0
1987	$ 0	$	0	$ 0	$ 0
1988	$ 0	$	78,836	$ (78,836)	$ (94,526)
1989	$ 0	$	186,681	$ (186,681)	$ (204,416)
1990	$ 173,439	$	180,781	$ (7,342)	$ (7,342)
1991	$ 183,652	$	175,236	$ 8,416	$ 7,686
1992	$ 177,941	$	169,850	$ 8,092	$ 6,749
1993	$ 172,557	$	164,388	$ 8,169	$ 6,222
1994	$ 167,137	$	158,876	$ 8,261	$ 5,746
1995	$ 161,631	$	153,364	$ 8,268	$ 5,252
1996	$ 156,120	$	147,850	$ 8,270	$ 4,798
1997	$ 150,607	$	142,337	$ 8,269	$ 4,381
1998	$ 145,093	$	138,260	$ 6,834	$ 3,306
1999	$ 139,581	$	135,583	$ 3,998	$ 1,767
2000	$ 137,225	$	132,054	$ 5,171	$ 2,087
2001	$ 133,819	$	128,524	$ 5,295	$ 1,951
2002	$ 130,289	$	124,995	$ 5,295	$ 1,782
2003	$ 126,759	$	121,465	$ 5,294	$ 1,627
2004	$ 123,230	$	117,936	$ 5,295	$ 1,486
2005	$ 119,700	$	114,406	$ 5,294	$ 1,357
2006	$ 116,171	$	110,876	$ 5,295	$ 1,239
2007	$ 112,641	$	107,347	$ 5,295	$ 1,132
2008	$ 109,111	$	103,818	$ 5,294	$ 1,033
2009	$ 105,582	$	100,288	$ 5,294	$ 944
2010	$ 102,053	$	96,758	$ 5,295	$ 862
2011	$ 98,523	$	93,229	$ 5,294	$ 787
2012	$ 94,993	$	89,700	$ 5,293	$ 719
2013	$ 91,465	$	86,170	$ 5,295	$ 657
2014	$ 87,935	$	82,640	$ 5,295	$ 600
2015	$ 84,405	$	79,111	$ 5,294	$ 548
2016	$ 80,875	$	75,582	$ 5,293	$ 500
2017	$ 77,347	$	72,052	$ 5,295	$ 457
2018	$ 73,817	$	68,522	$ 5,295	$ 417
2019	$ 70,287	$	64,993	$ 5,294	$ 381
2020	$ 66,757	$	61,464	$ 5,293	$ 348
2021	$ 63,229	$	57,934	$ 5,295	$ 318
2022	$ 59,698	$	54,404	$ 5,294	$ 290
2023	$ 56,169	$	50,875	$ 5,295	$ 265
2024	$ 52,639	$	47,346	$ 5,294	$ 242
2025	$ 49,110	$	43,816	$ 5,294	$ 221
2026	$ 45,581	$	40,287	$ 5,294	$ 202
2027	$ 42,051	$	22,300	$ 19,751	$ 687
2028	$ 38,523			$ 38,523	$ 1,225
2029	$ 3,186			$ 3,186	$ 92
PV $				$ 0	$ (235,923)

Table 9

Revenue Requirement Reduction Associated With the Intermediate Term Sale of Energy and Capacity (from D-17) (Thousand $)

Adjustments to Operation and Maintenance Expenses and Other Taxes (a)		
Book Depreciation (C-2)		
Production and Transmission ($297,280 + $11,995) x 4.563% (b)		$14,112
General and Common $6,114 x 3.811% (c)		233
Total depreciation		$14,345
Production and Transmission Operating and Maintenance Expense (Less Fuel) $655,291 x 4.563% (b)	$29,901	
Administration and General Expense $176,184 x ($29,901 / $898,336)(d)	5,864	
Subtotal Operating and Maintenance Expenses		$35,765
Ad Valorum Taxes		
State ($71,372 x 3.811%)	$2,720(e)	
Federal $27,912 x ($35,765/$1,074,520)	929(f)	3,649
Total Expense Adjustments		$53,759
Adjustment to Income & Deferred Taxes		
Increase in Income Taxes $53,759 x 39.61%		$21,294
Increase in Income Taxes due to Removal of Additional Depreciation for tax purposes $251,600 x 39.61% x 3.811% (g)		3,798
Reduction in Taxes due to Deferred Taxes Removed $115,167 x 3.811% (h)		(4,389)
Increase in Income for Return		$33,056

(a) Proforma expenses at present rates, but excluding adjustment D-17
(b) Allocation factor 400 MW intermediate term sale divided by 8766 MW total installed capacity.
(c) Total General and Common depreciation times total plant allocator (3.811%), (See Table 11).
(d) Total A&G expenses times allocated production and transmission expenses divided by total operation and maintenance expenses less fuel and A&G.
(e) State and local taxes less gross receipts tax times total plant allocator (3.811%).
(f) Federal taxes other than income times allocated production, transmission and administrative and general expenses divided by total operation and maintenance expenses less fuel.
(g) Excess of proforma total tax depreciation over book depreciation (D-7 less D-6) times 39.61% income tax rate times total plant allocator (3.811%).
(h) Proforma tax deferral (D-8) times total plant allocator (3.811%).

Revenue Requirement Reduction Associated with the Intermediate Term Sale of Energy and Capacity (Thousand $)

Reduction in Plant in Service	
Original Cost of Plant (a)	$483,980
Less: Book Reserve (a)	(83,944)
Net	$400,036
Associated Materials and Supplies - Fuel (e)	$10,983
Less: Accum. Deferred Income Taxes (f)	33,198
Total Rate Base Deduction	$377,821

(a)

	Production	Transmission	Distribution	General and Common	Total	Total Plant Allocator
Total						
O.C.	$9,761,470	$681,513	$2,054,790	$202,203	$12,699,976	100%
Reserve	1,549,180	237,134	606,093	71,458	2,463,865	
Net					$10,236,111	
Allocated Portion						
O.C.	$445,416 (b)	$31,097 (b)	-	$7,467 (c)	$483,980	3.811%
Reserve	$70,689 (b)	$10,820 (b)	-	$2,435 (d)	83,944	
Net					$400,036	

(b) 400 MW intermediate term sale divided by 8766 MW total installed capacity = 4.563% of total (Allocation Factor).

(c) (Production and Transmission O.C. Plant)/(Total O.C. Plant less General and Common) x Allocation Factor (4.563%).

(d) (Production and Transmission Plant Reserve)/(Total Plant reserve less General and Common) x Allocation Factor (4.563%).

(e) Fuel inventory [$16,550 (C-7) + $9,626 (C-7) + $214,522 (C-8)] x Allocation Factor (4.563%).

(f) Total Accumulated deferred taxes (B-15) times total plant allocator (3.811%).

5/11/89

ANALYSIS OF
ACCOUNTS WITH A SPECIAL AGREEMENT -- SPECIAL RUN
ALL ACCOUNTS
CURRENT BILL CLASSIFICATION ONLY CHECKED FOR DELINQUENCY

TOTAL MONTHS TO REPAY (1)	TOTAL CUSTOMERS ON SA (2)	CURRENT BILL MINUS S A INST (3)	TOTAL S A BALANCE (4)	TOTAL OF INSTS	# OF PASTDUE ACCTS	PERCENT PASTDUE	TOTAL CUSTOMER BALANCE	ACCTS WITH NO FIN CHG	S A UNBILLED W/NO FIN CHG
OVER 300	8,252	719,042.02	13,070,189.44	16,420.99	4,125	49.98	16,172,190.03	8,079	12,592,129.90
OVER 200	2,638	187,086.74	3,021,039.29	12,454.00	1,632	61.86	3,782,861.08	2,441	2,638,093.93
OVER 100	6,077	439,042.63	5,918,513.71	42,907.90	4,227	69.55	7,577,406.27	5,212	4,699,462.25
OVER 60	5,996	403,248.74	4,025,785.34	63,377.99	4,180	69.71	6,327,375.10	4,661	3,330,275.97
OVER 48	3,181	212,179.36	2,200,186.47	41,064.50	2,202	69.22	2,960,954.49	2,282	1,341,837.97
OVER 36	6,212	415,480.77	4,417,056.68	108,790.09	4,240	68.25	5,836,135.49	4,448	2,835,576.55
OVER 24	9,549	629,256.35	5,616,993.06	180,794.45	6,727	70.44	8,048,809.60	5,808	3,008,127.05
OVER 12	13,744	881,001.94	5,889,121.28	345,897.74	9,480	68.97	9,280,626.45	6,109	2,189,530.37
OVER 6	12,073	771,734.92	3,923,776.04	459,243.00	8,077	66.90	6,921,409.66	3,799	1,118,401.58
UNDER 6	23,567	1,512,548.31	3,760,893.34	1,515,251.89	15,209	64.53	10,107,709.20	5,948	923,843.96
FINAL TOTAL	91,289	6,171,429.78	52,651,554.65	2,794,210.63	60,099	65.83	77,023,557.37	48,787	34,677,280.33
TOTAL OVER 48	26,144	$1,961, 399.4[illegible]	$2[illegible],043,[illegible]14.25						

Table 12

Philadelphia Electric Company - Electric Operations
DEVELOPMENT OF UNCOLLECTIBLE ACCOUNTS EXPENSE COMPONENTS
($1,000)

A. Amortization of Existing Special Agreements Over 4 Years (Table 12, Col. 4)

Term of Agreement	Balance @ 5/1/89
Over 300 Months	$13,078
Over 200 Months	3,021
Over 100 Months	5,919
Over 60 Months	4,826
Over 48 Months	2,200
Total	$29,044
6 Year Amortization	$4,841

B. Normalization adjustment to uncollectible accounts to reflect a pro forma level of CAP customers (26,000 customers)

1. Total CAP Related Uncollectible Accounts Expense for 26,000 customers

Period of Agreement	Current Monthly Billings (Table 12, col. 3)	
Over 300 Months	$720	
Over 200 Months	187	
Over 100 Months	439	
Over 60 Months	403	
Over 48 Months	212	
Total	$1,961	
Estimated Annual Bill ($1,961 x 12 mos)	$23,532	
Unrecoverable portion of current billings @ 71.6% (a)		$16,850

2. CAP Uncollectibles Included in Future Test Year

Total Special Agreement Uncollectible Accounts		$11,694 (a)
Ratio of Special Agreements Balance over 4 years to Total Special Agreement Balance (Table 12, Col. 4) ($29,044 / $52,652		55.162%
Special Agreements Over 4 Years (per above)	$29,044	
Test Year CAP Uncollectibles		$6,451

(a) Based upon an analysis of the February 1989 bills of 5,006 CAP customers
(b) Based on an analysis of gross write-offs for the 12 months ended 3/31/89

	Gross Write-Offs 12 Months Ended 3/31/89	%	Net Write-Offs 12 Months Ended 3/31/90
Regular	$15,447	51.1	$12,220
Special Agreement	14,762	48.9	11,694
Total	$30,209	100.0	$23,914*

*Per Exhibit TPH-2, page B-12

Background and Qualifications of

Thomas P. Hill, Jr.

Q. Mr. Hill, please discuss your responsibilities in the various assignments and positions you have held at Philadelphia Electric Company.

A. As an Engineer in the Rate Division, I worked in a variety of areas which have included economics and statistical analysis of Company operations. In conjunction with this work, I was an instructor, from 1976 to 1984, in the Company's Engineering Economics Course.

My specific responsibilities as an Engineer included cost analyses, development of tariff pricings, and investigation of various rate forms for all resale and wholesale tariffs of the Company. I have worked extensively in the preparation of materials required for rate filings before the Pennsylvania Public Utility Commission, the Public Service Commission of Maryland, and the Federal Energy Regulatory Commission. In addition, I have worked on the design, filing, and implementation of both State and Federal Fuel Adjustment Clauses. Additionally, I have participated in development of the Plant Mortality Studies required for the determination of depreciation rates for all Company operations and the determination of depreciated plant in service.

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

As Assistant Manager, I reported to the Manager of the Rate Division and shared with him the responsibilities that related to the development of tariffs and rates on file with Federal and State Regulatory Commissions, the preparation of all necessary supporting data, the administration of these tariffs and the completion of various studies as assigned by top management.

As Manager, I report to the Vice President of Rates and administer under his direction the various functions of the Rate Division.

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

Following completion of this rate proceeding I will assume the position of Controller for Philadelphia Electric Company. I will report to the Senior Vice President of Finance and have management responsibility for the accounting operations of the Company. General Accounting Division, Plant Accounting Division, Budget and Control Division and Accounts Payable Division will report to the Controller's Division.

Q. What are your professional affiliations?

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

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

A. I have participated in the preparation of rate case materials necessary for filing electric rate applications before the Pennsylvania Public utility Commission which include: the 1975 Electric Rate Case (RID 295), the 1977 Electric Rate Case (RID 438), the 1979 Electric Rate Case (R-79060865), the 1980 through 1985 Electric Rate Cases R-80061225, R-811626, R-822291, R-842590 and R-850152. At R-79060865, I submitted testimony in the area of nuclear fuel inventory, materials and supplies, land held for future use and non-revenue producing CWIP. At R-80061225, R-811626, R-822291, R-842590 and R-850152, I presented testimony on specific revenue adjustments, operating expenses and the Company's claimed rate base exclusive of depreciated plant in service.

In addition, I have participated in the preparation of similar materials in prior Gas Operations filings including the 1979 Gas Rate (R-79030781), the 1981 Gas Rate Case (R-811719), the 1983 Gas Rate Case (R-8432410) and the 1987 Gas Rate Case (R-870629). At R-79030781, I presented testimony as the Company depreciation witness responsible for claimed rate base and annual provisions for depreciation. At R-811719, R-832410 and R-870629, I presented testimony in support of the Company's revenue claim, operating expenses and rate base exclusive of depreciated plant in service.

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

I have participated since 1970 in the preparation of exhibits for rate base, revenue, expense and other adjustments necessary for filing rate applications before the Federal Energy Regulatory Commission in support of our rate increases to the Borough of Lansdale and Conowingo Power Company. I have submitted testimony before the FERC at Dockets ER81-318, ER82-294, ER82-295, ER84-9 and 10, ER86-622. I have also prepared rate filing material including rate base and all adjustments to rate base for filings before the Public Service Commission of Maryland for our subsidiary Conowingo Power company.

Finally, I have submitted testimony in several Show Cause proceedings before the Pennsylvania Public Utility Commission. At Dockets No. R-830453, No. M-840375, No. M-850010, and No. I-880082 I testified on the administration of the Company's Energy Cost Rate and at Docket No. I-840381, I testified on the revenue requirements for Limerick 2 and other alternate generation scenarios.

ORIGINAL R-891364

PECO STATEMENT NO. 7

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DIRECT TESTIMONY

OF

WILLIAM A. ABRAMS

LIMERICK PROJECT

FINANCIAL MANAGEMENT

RECEIVED

JUL 21 1989

SECRETARYS OFFICE
Public Utility Commission

July, 1989

<u>DIRECT TESTIMONY OF WILLIAM A. ABRAMS</u>

Q. Please state your name and business address.

A. My name is William A. Abrams. I am Group vice President of Duff & Phelps Inc., 55 East Monroe Street, Chicago, Illinois.

Q. Describe briefly your educational background and business experience.

A. I received a Bachelor of Science of Commerce degree from Loyola University (Chicago, Illinois) in 1951, majoring in business administration.

From 1951 through 1957, I worked for several firms in industry. I was responsible for various phases of credit analysis and approval for Walter E. Heller Company and Steel Products Engineering Company, Inc. In 1953, I joined Uniroyal, Inc., where I was involved in sales administration, contract cancellation negotiations, production coordination, forecasting and accounting.

In 1958 and 1959, as a principal of Curran, Bayliss & Glasgow, Inc., a management consulting firm, I performed analyses of, and made recommendations for improvement of client internal operational systems, evaluated merger-acquisition situations, and consulted on financial planning. From 1960 until 1967, I was engaged in corporate finance, initially as Assistant to the President of Hyman-Michaels Company and subsequently with Benjamin Lewis & Company, investment bankers. I was responsible for negotiating large railroad and other types of equipment lease transactions financed by private placement with institutions, merger-acquisitions, private corporate financing and municipal bond underwriting.

I joined Duff & Phelps in 1967 as a senior financial analyst to perform special company valuation studies and to analyze the securities of companies, principally in the electric equipment industry. From 1969 to the present, I have been in our Utility Research Division. Until 1980, my primary responsibilities were to analyze a group of individual utility companies, particularly in California, the Mid-West and on the East Coast. My work included analysis of the earnings potential of these companies, their financing requirements, coverage ratios of interest and preferred dividends, and cash coverage of common dividends. From 1974, I was also the Chairman of our Utility Fixed Income Rating Committee. I regularly consulted with and advised our clients on public utility fixed income and common stock investments and was a member of the Senior Office Committee, which reviews and finalizes the Duff & Phelps' Regulatory Rankings.

Since 1980 my responsibilities have been entirely with the Duff & Phelps' Fixed Income Rating Service. I am Vice Chairman of the Duff & Phelps' Fixed Income Rating Committee. As a member of this Committee, I participate in interviewing and analyzing companies and assigning ratings to their fixed income securities.

Q. Have you testified in other regulatory proceedings?

A. I have testified before the California, Michigan, Minnesota, New York, North Carolina, Maryland, Maine, Mississippi, New Jersey, Texas, Arizona, Pennsylvania, Nevada, Kansas, Indiana, and District of Columbia Commissions, the Georgia Legislative Committee on Utility Regulation, and before the FERC on the subjects of rate of return, financing, and factors affecting credit ratings.

I have lectured on rate regulation, utility financing, and the analysis of public utility companies and their securities to classes of graduate students at Northwestern University and as a guest faculty member for the Executive Development Center seminars sponsored by the University of Illinois and the University of Notre Dame. I have given speeches and served on panels on utility matters before investor, utility, and expert witness groups; the PUR Financial Conference; Edison Electric Institute conferences; the Iowa State University Regulatory Conference; Merrill Lynch Capital Markets seminars; NARUC; and the Society of Rate of Return Witnesses. I write articles on utility-related subjects for publication in "Credit Decisions," a weekly credit review published by Duff & Phelps.

Q. Are you a chartered financial analyst?

A. Yes. On the basis of my experience and a series of written examinations, I was awarded that designation by the Institute of Chartered Financial Analysts in 1971.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Investment Analysts Society of Chicago; the Fixed Income Group of the Chicago Society; and the Utility and Telecommunications Securities Club.

Q. Please describe the business of Duff & Phelps?

A. Duff & Phelps is a large independent investment research organization. The utility division of Duff & Phelps is retained in a professional advisory capacity for advice and consultation on investments in public utilities' securities by more than 350 financial organizations.

Our clients include the following types of investors: insurance companies, banks, trust companies, mutual funds, universities, and pension and retirement funds. In addition, we have as clients a number of investment counseling and securities firms. Thus, directly and indirectly, Duff & Phelps provides independent, objective, professional investment research to a very large cross section of investors of all types. For the purpose of providing our clients with information concerning investment risks, we have for many years rated the fixed income securities of utility, industrial and financial companies. We rate about 200 utility companies of which 116 are electric and electric/gas combination companies. In developing these ratings and the factors which influence them, it is our purpose to focus on those factors we consider to be related to risk. Duff & Phelps does not act as broker, dealer or underwriter of securities.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents my views and those of Duff & Phelps respecting the financial condition of the electric utility industry in the 1970s, the causes of the degrading of the industry's financial condition and the similar experience of Philadelphia Electric Company

("PECO") during that period. Further, against the background of this data, I will present my and Duff & Phelps' views on the reasonableness and necessity of the Company's 1976 and 1978 decisions to defer the Limerick project, and Limerick 2 in particular.

I next will present my judgment as to whether PECO could have raised the additional capital needed in the period 1976 through 1982 to complete Limerick 1 and common on an accelerated basis in order to meet the November 1983 commercial operation date suggested in the Commission's decision in the Limerick 1 rate case. Here I also will review the likely impact these additional financings would have had on the Company's cost of capital in the period, assuming the required financings could have been placed. I additionally will consider the question whether the Company might have proceeded with accelerated construction of the entire Limerick project during the period 1976 through 1982 and will discuss whether PECO was in a position to place the still higher financings which would have been required under this scenario.

Q. How have you organized your testimony?

A. I begin with a description of how Duff & Phelps evaluates the financial integrity of electric utilities and then describe the factors which control our assignment of credit ratings. As part of this discussion, I explain the effect which regulation and its decisions respecting specific issues of importance to the investment community have upon those evaluations.

Next, I describe the financial condition of PECO and the electric industry in the 1970s, the factors which changed that condition adversely and the effect of those changes on investor perceptions of the industry.

I then present my and Duff & Phelps' evaluation of PECO's decisions in 1976 and 1978 to reduce its capital expenditures and whether the Company could have raised the additional capital needed to permit an earlier completion of Limerick 1 and common by November 1983.

Finally, I present my and Duff & Phelps' findings on the feasibility of financing the additional investment which would have been required in order to proceed with accelerated construction of both Limerick 1 and Limerick 2 in the period 1976 through 1982.

Q. How do you define financial integrity?

A. Financial integrity refers to the soundness or stability of the enterprise. This means the ability of the business to resist downward financial pressures and the existence of sufficient buffers from unexpected adverse developments so that any distortions can be quickly remedied without impairing either the orderly conduct of the business or the credit quality of outstanding and future fixed income securities. In other words, we examine the stability and protection of the income stream. It also means the assurance of confidence in the earnings return potential of the enterprise so that capital -- both debt and equity -- can be attracted on a reasonable basis.

Q. What analysis is made to ascertain the financial integrity of a utility company?

A. There are two parts to any analysis of a utility company to determine its financial integrity. The analysis is both qualitative and quantitative.

Qualitative aspects for an electric utility (on both a current and prospective basis) include the viability of the service area (jobs, industrial diversification, sales outlook, state and local government policies); power supply (reserve margins, age of units, purchased power sources); fuel supply (diversity, cost, availability); regulatory principles (extent of recognition of operating costs, capital costs and cash flow needs, and consistency); management (recognition of problems and development/implementation of solutions, depth); quality of earnings (cash generation); and quality of balance sheet (capital structure, off balance sheet financing and liquidity).

To quantify financial protection, certain measures are used. For example, we look for coverages, principally excluding AFUDC, to be steady within a range appropriately reflecting other risks to which the business is exposed. The capital structure must contain sufficient equity support to protect the senior securities. The forward construction program and other fund needs relative to the size of the company are examined to ascertain whether the required capital growth rate will be a strain. Returns allowed and earned must be sufficient to attract capital for the ongoing needs of the company.

Q. Are credit ratings based only on historical data, or are ratings also determined on the basis of anticipated results?

A. The historical financial record of a company and its current status are certainly important to demonstrate how it has been run, how it has been regulated, and how its problems have been solved. A company with a long record of poor financial performance generally must demonstrate a long period of sustained improvement before it will be upgraded. This is in contrast to a company with good financial stability that experiences a temporary dip in performance which is quickly corrected.

Business characteristics interact with financial standards, and where there are unfavorable business characteristics, there must be offsetting financial protection. Conditions external to the company can add to risks.

The history of the company is studied to give some perspective to the future. The past record gives credibility to future assumptions. The future view must recognize the extent to which ongoing conditions are apt to be different from the past. Naturally, the longer the future period the less clear the picture will be. The rating agency attempts to forecast the safety or absence of major problems of quality deterioration over the next year, the next three years, the next five years, etc. It calculates, for example, whether a company can attract from the market the money it will need to finance its construction commitments, or to meet other funding requirements such as debt maturities while achieving or maintaining coverages and other financial ratios satisfactory for its particular quality rating.

Q. What is the role of regulation in the financial integrity of a utility?

A. Investors, investment advisors, and rating agencies such as Duff & Phelps regard regulation as a key factor in assessing a utility company. A utility's financial condition is assessed on many bases all of which are related to the ability of the company to earn a realistic rate of return, the cash quality of earnings, the stability of earnings, and moderation of the company's need to finance externally. Important considerations are the allowed rate of return; proper recognition of test year sales, expenses, and rate base; the relationship of the test year and timing of the rate increase to the period when those rates will be in effect; and the recovery of capital. Built into these considerations are the mechanisms in place which enable rates to be adjusted to recognize swings in major costs which might not be capable of accurate forecasting. An example is the fuel clause and the timeliness of its operation. To the extent that rising fuel costs are not offset in their entirety or in a timely manner, business risk is increased and financial risk (amount of debt financing) must be decreased. This requires a stronger capital structure (higher common equity support), and a higher level of interest and preferred stock coverage to maintain the financial integrity of the company. All of these items must be considered in rating a company.

Q. Why is the recognition of rate base considered important by investors?

A. Unlike most other industries, the utility company is required by its franchise to meet the demand of its territory. The plant it builds is highly capital intensive relative to the revenue it can generate. Construction lead time for generating plant is long. The plant is not multi-use, and cannot itself be sold or transported into different markets, although its energy output may be sold, if there is a demand for it. Plant is built based on projections of customer demand growth which is extremely difficult to forecast accurately. Plant also may be started (or built) to diversify fuel sources (e.g., away from oil/gas) and, of course, to replace aging units. Further, in many cases, the plant must be designed of a size that results in extra capacity when the unit goes into service. Substantial funds must be expended for preliminary engineering, environmental studies and various regulatory approvals before ground is even broken.

A radical decrease in demand patterns can occur during the construction phase. Also, other outside changes can alter the economic feasibility or even prevent the completion of the unit. For example, inflation, rapidly rising capital costs and mandated design changes have raised the cost of nuclear plants far beyond initial estimates. Political opposition may also develop to oppose a construction project on environmental grounds.

If recovery of cost and a return on capital investment in a plant is not permitted, investors will be loath to put new money into utilities in that state. Ratings will reflect the added risk and any funds which may be available for future service of the ratepayer will be at higher cost. Given the importance of the rate base issue in today's investment environment and typical utility involvement with large construction work in progress balances, unfavorable regulatory action on this issue alone can precipitate downgrades which cannot be reversed for many years.

Q. In their appraisal of the financial integrity of a utility company, are investors and the rating agencies concerned with utility cash flow and regulatory position on issues which could impact cash flow?

A. Yes. For example, a current cash return on CWIP is very important. The debt holder is concerned about the protection (coverage) of the company's interest obligation. As mentioned above, interest must be paid in cash, not AFUDC which is a non-cash credit. Therefore, the extent to which CWIP is included in rate base or some other form of current rate support for construction is provided became, in the early 1970s, one of the key factors considered by Duff & Phelps.

If current "cash" rate support is not provided, increased CWIP balances cause a wider spread between coverages including AFUDC and coverages excluding AFUDC. When this happens, investors realize that a large proportion of their utility investment is not earning a cash return and that cash protection of interest payments is less. The financial integrity of a utility company becomes weaker as its non-earning assets become larger unless a compensating higher return is achieved on the earning assets. Investors recognize that where regulatory bodies permit no cash earnings on investment under construction, financial integrity is in jeopardy and, for that reason, tend to regard such companies as having more risk than would otherwise be the case.

Q. You mentioned that debt holders are concerned with the protection of interest obligations as measured by coverages. How does Duff & Phelps assess coverages?

A. Coverages can be calculated on a pretax or on an after-tax basis. These also are considered including or excluding AFUDC. Duff & Phelps uses pre-tax coverages excluding AFUDC as the primary indicator. Major non-cash earning effects from accrued revenues and/or expense deferrals also are considered.

Q. Why do you follow this methodology?

A. There are several reasons we consider coverages excluding AFUDC as the primary indicator. AFUDC is an accounting method which recognizes that the capital costs of debt and equity used during construction are part of the total cost of building plant to serve the utility's customers. Thus, these costs have to be added to the construction work in progress asset which ultimately becomes rate base. To accomplish this, reported earnings are credited (increased) by AFUDC based on a formula designed to compensate for the equity and debt funds used each year for construction. For each accounting period, the amount of AFUDC increases retained earnings on one side of the balance sheet and the CWIP account on the other side of the balance sheet. AFUDC is also compounded. By this, I mean that AFUDC builds upon AFUDC as well as on labor and hardware costs during the construction period. The expectation is that the utility will earn a future return on the accumulated AFUDC when the construction project is completed, put into rate base, and is allowed a revenue return. AFUDC is then depreciated as part of the total plant account.

I mentioned that AFUDC is an accounting treatment. There are accounting treatments to record all of a utility's transactions. The fact that an accounting treatment is correct from a recording standpoint does not mean that the event or business condition it is recording is desirable. An example I have used is that there is an accounting treatment to record uncollectible accounts receivable. While uncollectible receivables are a fact of life and they must be accounted for, they are not desirable. The larger they are, the less desirable the condition of the company. My point in this example is that the financial condition which underlies the accounting treatment is what must be considered in determining a company's financial integrity.

When AFUDC was originated, it was never thought that non-cash earnings would reach the proportion of reported earnings they had beginning in the 1970s nor that AFUDC would continue as a major part of earnings for such an extended period of time. This condition was brought about by several factors:

1. The inflation rate (actual and anticipated) which raised the cost of all capital.

2. Government regulation which increased the cost and extended the completion time of plant. Inflation compounded the impact of this factor.

3. The inadequate levels of earned returns on operations.

The real world expects to be paid in cash. No company can operate for long without impairing its financial integrity when major and ever-increasing portions of its reported earnings are composed of non-cash, bookkeeping entries. The utility company must pay dividends and interest in cash. It has to pay its contractors on a construction project in cash. So too, it must have cash to pay its suppliers of fuel, its labor, and its taxes. It takes cash to carry the company's accounts receivable. When that cash is not earned, the company has to enter the capital markets for the cash to pay its bills and honor its construction commitments. This process increases capital costs, increases AFUDC, and reduces real earnings.

Recognizing that interest has to be paid in cash, we use the pre-tax coverage of interest excluding AFUDC to measure the protection which cash earnings provide to the debt holder. In our assessment of reported coverages, we also consider deviations caused by major non-cash earnings produced by various revenue accruals, expense deferrals, and off balance sheet obligations.

Q. What was the investment community's view of the electric utility industry during the 1970s?

A. Investors were concerned with a number of basic fundamental changes which had impacted, and were continuing to affect the electric utility industry, including:

1. Rapidly rising operating and capital costs.

2. Regulatory changes.

3. The economy and electric utility sales prospects.

4. Financial deterioration.

Q. Could you describe the trend in operating and capital costs?

A. Yes. Through the mid-1960s, the electric business was a declining cost industry. New technology and economies of scale enabled the industry to effect unit price reductions. Of course, this had the effect of contributing to sales growth which, in turn, lowered capital costs per unit of Kwh. From 1960 to about 1965, the industry "rode down the reserve" as sales grew rapidly into available capacity.

In the mid-1960s, a new building program was initiated by the industry in response to projections of continued rapid sales increases and the national concern for low reserve margins which was highlighted by the New York City blackout of 1963. The industry then had in service many "tea kettles" (generating units from the 1920s to 1940s) which were small, relatively inefficient, and aging. The capital expansion program which followed was weighted heavily in favor of the nuclear option. Of the 95 major U.S. electric utility companies, about 70 were involved in nuclear power plant construction in this period.

As this new building program got underway, national economic conditions began to change. Inflation accelerated, and interest rates responded to actual and anticipated inflation, to the rising trend of government and corporate borrowings, and to the surge in electric utility company financings.

In the second half of the 1960s, there developed a national and local concern for the environment. The utility companies, encouraged by price and need to reduce coal emissions, converted older coal units to oil and built large, new oil units. However, by the late 1960s, low sulphur oil was mandated in many areas. This type of oil was in shorter supply, and the higher price drove up fuel costs in the late 1960s and early 1970s. The 1973 Arab oil embargo was a major shock to operating expenses. The quantum oil price increases in 1973-74 were followed by a complete revamping of fuel pricing. Thus, gas and coal followed oil in the upward spiral through 1980. Through this same period, the use of low sulphur coal or scrubbers was mandated, further driving up operating and capital costs.

Q. What regulatory changes affected the electric utilities through the 1965-80 period?

A. The principal regulatory changes occurred in three areas:

1. Environmental regulation.

2. NRC regulation.

3. State utility and FERC regulation.

These areas are not entirely separable because the costs imposed by environmental agencies and the NRC had to be faced by the state regulatory commissions and the FERC.

Q. Please elaborate.

A. In the late 1960s, national, state and local concerns for the environment exploded. As mentioned above, SO_2

restrictions mandated the use of higher cost fuels and, in many cases, scrubbers which, at once, increased operating and capital costs, and also reduced plant efficiencies. So too did environmental impact studies and plant siting requirements. In 1978, the Power Plant and Fuel Use Act moved to set priorities for so-called premium fuels with the electric utilities having the lowest priority.

At the same time, nuclear concerns (indeed, anti-nuclear sentiment) surfaced. This led to more and more stringent NRC safety requirements, plant retrofit, redesign and construction delays. Of course, the 1979 TMI incident served to multiply NRC changes for plants nationwide.

These environmental and NRC changes were made with little or no concern for capital cost or economies of operation. The basket of higher expenses (environmental, NRC, rate base additions, operating and capital) came home to the state regulatory commissions in the form of rate requests.

My perception of the state regulatory bodies is that they were not prepared to handle the surge of rate increase requests that began in the late 1960s. Most important initially were rate lag and recognition of inflation and cost of capital. Annual rates cases filed almost tripled from 1970 to 1980.

Rate cases took one to several years to decide. Most test periods adopted were historic and did not reflect the ongoing rate of inflation. The regulators generally took the position that, even though inflation existed in the test year, it would stop. Similarly, although the cost of money was demonstrably higher in the test year and at the time of decision, regulators tended to look backward. Thus, allowed rates of return were lower than the true cost of capital.

Similarly, the regulators refused to recognize the burgeoning cash needs of the electric industry. The quality of earnings became an ever more important issue as the industry struggled to raise depreciation rates, utilize deferred accounting for income tax benefits, and obtain a revenue return on construction work in progress.

Investors had come to realize that the utility companies could not pay their bills with ever mounting AFUDC credits. These concerns were evident in the drop of the industry's P/E multiple which peaked at 24.7x in 1961, slipped to 22.7x in 1964, then dropped to 18.8x in 1966, and trended downward from 16.3x in 1967 to 11.9x in 1972. When Con Ed passed its dividend in

March 1974, the investor focus on cash intensified, and the industry P/E multiple soon dropped to 6.4x. This decline only compounded the disastrous effects of the 1973 oil embargo and the ensuing quantum jump in fuel prices. Investors and their advisors began to calculate interest coverages and dividend coverages excluding AFUDC. These data are shown in my Schedule WAA-1.

Rate hikes to cover fuel cost increases (even though some states deferred increases thereby exacerbating the cash problems of the companies) focused greater public and media attention on the utilities. Investors became increasingly concerned whether rate treatment would be adequately responsive. At the same time, various interest groups pushed conservation, alternate energy sources and "no-growth" scenarios, creating public concern over the concept of new central station generating plants. Regulation in some states reacted by delaying rate cases, switching to elected commissions, abandoning fair value principles, and generally opening hearings to more intervenor groups. Rate design was changed to promote conservation, to minimize residential price increases, and often to reduce sales.

It took until the late 1970s for regulation in general to gear up to the press of a far larger number of rate case filings (annually for many companies), to recognize more nearly the cost of money, to update test years, and to provide measures to help halt the erosion in earnings quality.

Q. How did economic conditions in this period affect investor concerns about the electric utilities?

A. Certainly the persistence of inflationary trends was recognized as having an adverse impact on the capital intensive electric utility industry. Many major investors got out of utility equities. Lower quality securities became more difficult to sell. Some companies avoided (e.g., by borrowing from banks) selling debt publicly which might lead more immediately to a debt rating downgrade.

Q. What was the electric utility industry's performance during this period?

A. Selected financial data (Schedule WAA-2) shows the following. Debt ratios slowly began to retreat from the 1970 peak level of 57.1%, but moderated only to the 52% to 53% range by 1978-80. Annual capital growth expanded rapidly from 12% in 1970 to 14.2% in 1974. This measure eased in 1975-78 as the industry completed, cancelled, or delayed plant construction.

Average debt interest costs increased steadily with frequent borrowings at new debt rates above embedded rates. Thus, this measure increased from 5.3% in 1970 to 9% by 1980. Returns earned on common equity held near 12% until 1974 when fuel prices and far higher capital costs drove the return down to 10.4%. This measure partially recovered in 1975 and fluctuated upward to 12% again in 1980.

In this environment, coverages excluding AFUDC declined steadily from 3.1x in 1970 to 2.2x in 1974. A four-year partial recovery was reversed in 1979 and coverages returned to 2.2x in 1980.

The performance of the industry's common stock capsulized the attitude of the investment community during this period. Market to book ratios (which were 200 to 280 from 1960-68) declined to 163 in 1970. The drop to 102 in 1973, as a result of the oil embargo in the fall of that year, was shortly followed by Con Ed passing its dividend. This action crystallized for the investment community the underlying cash strain problems of the industry. As a result, the market to book ratio collapsed to 70. After returning to near unity for several years, this ratio dropped again in the late 1970s as inflation and interest rates increased, with the sharp fuel price hikes experienced in 1979 and (for nuclear companies) the 1979 TMI nuclear accident.

Q. Please describe PECO as it existed in 1970.

A. PECO entered the 1970s with low generating reserve margins, and sales and peak load growth which, though below the industry average, were high for a mature territory. In 1970, 51% of generating capacity was oil fired, and 56% of the energy generated was by oil.

Q. What was the financial position of PECO from 1970 through 1980?

A. The financial position of PECO can be quickly ascertained by reviewing certain financial ratios shown in my Schedule WAA-3. Comparison of these data with similar data discussed earlier for the industry (Schedule WAA-2) gives a basis for measuring how PECO compared with the industry in those years.

As with many companies in that era, PECO was pressured to build for unexpectedly rapid growth and for fuel diversification. This building program accelerated rapidly in the late 1960s so that capital growth by 1970 was very heavy at 16 1/2%, more than one-third greater than the 1970 industry average of 12%. Capital growth for the Company remained far higher than the industry through 1973 and was comparable to the industry peak in 1974. In the years 1975-80, reflecting the deferrals of the Limerick units the Company finally was able to reduce its capital growth rate below the industry average. PECO's average interest cost approximated the industry through 1973, but then increased faster than the industry so that the Company's debt interest cost in the late 1970s was 50 to 70 basis points higher than the average.

With the strain of construction financing and sub-par returns, PECO's coverages excluding AFUDC deteriorated rapidly. They fell from a respectable 4.3x in 1967 to a very sub-average 2.2x level by 1970. After a brief and small upturn in 1971-72, coverages resumed their downturn reaching 1.5x in 1980. Adjustment for non-cash deferred fuel cost accounting showed even more serious deterioration in 1974 and 1979 to 1.6x and 1.2x, respectively.

Rate relief granted through this period was inadequate to sustain returns near industry levels. In part because of the Company's large oil dependence, fuel cost increases commanded 2.63 cents of the total 4.54 cent 1970-80 increase in revenue granted per Kwh. Capital costs including return and all other expenses accounted for only 1.91 cents of the total 4.54 cent increase. With regulatory lag and rate case delays, PECO's earned returns were low throughout the period. In 1970 and each year 1973 through 1979 (a total of eight years), the return was under 10%. In only one year did the return exceed 11% (1971 at 11.6%).

Q. Please now present your and Duff & Phelps' evaluation of the reasonableness and necessity of PECO's decisions in 1976 and 1978 to reduce capital expenditures through deferral of the Limerick project.

A. A brief summary of the facts is appropriate first. In 1976, PECO announced a two-year delay in the completion of the Limerick station. The five-year, 1975-1979, construction forecast was lowered by $504 million to $2.080 billion. The 1978 deferral lowered the three-year 1978-80 forecast by $88 million to $1.278 billion. <u>See</u> Schedule WAA-4.

It was not uncommon for utilities to reduce construction expenditures during the 1970s. This was especially true of companies that were financially strained and/or where load growth forecast changes suggested a delayed need for the plant. Many units were cancelled, and at least a dozen nuclear and coal units were delayed. <u>See</u> Schedule WAA-5.

Schedule WAA-6 shows the 1970-80 Sources & Uses of Funds Statements for PECO. The Company's major projects through the early 1970s were the Peach Bottom units, the Salem units, and the Eddystone units. Internal cash generation was low and annual external financings ranged from $300 million to $500 million annually in 1970-75. These were large sums for a company with 1970 capitalization under $2 billion, especially when there was no respite. The Company's 1975 forecast showed the same pattern in 1975-79 when $320 to $523 million in annual financings were forecast.

By contrast, with the cuts in construction requirements, actual financings in 1975-79 ranged from $235 million to $370 million, as shown on Schedule WAA-6. The level of the reduction of construction expenditures is set forth on Schedule WAA-4 and varied from approximately $50 million to $270 million annually.

Q. In your view, what market forces made the 1976 and 1978 deferrals appropriate?

A. The single most important factor was the wide-spread and multi-faceted uncertainty of the period. The industry was in disarray beginning in 1973 due to:

- Acceleration of stringent and costly environmental regulations.
- The 1973 oil embargo and quantum increases in prices of all fuels.
- Fuel shortages and upset of long term supplies.
- Energy conservation and drop in demand and/or demand growth.

- Inflationary increases in operating, construction, and capital costs.
- Inadequate and delayed response by regulators.
- Falling returns on common equity and larger proportions of such returns comprised of non-cash AFUDC.
- A reduced ability to accurately forecast sales, peak demand, fuel costs, operating and capital costs, financing strategy, and regulatory support.
- The stress of record annual construction budgets since the late 1960s.
- The need to reduce construction budgets.

Investors responded to these uncertainties, which raised the fundamental risk of the industry, in a number of ways:

- They dropped their valuation of electric utility equities from a P/E ratio of 13.5x in 1970 to 8.8x in 1973 (oil embargo) and 6.4x in 1974 (fuel prices and Con Ed passing its dividend). After a modest recovery to an average of less than 9.0x 1975-77, this ratio dropped to 7.6x in 1978, and was 6.1x by 1980.

- Investors began to distinguish far more between companies based on type of fuel, sales growth, construction budget, regulatory differences, and financial integrity (credit ratings).

- Investors required higher and higher yields on bonds due to inflation and/or inflationary expectations.

- They demanded tougher restrictions, shorter terms, and/or declined to purchase the bonds of weaker utility credits.

- Many large institutions simply left the utility equities market altogether.

PECO shared all the uncertainties of the industry and was financially weaker than the industry average.

- In 1973, 44.7% of its generation was fueled by oil.

- Its interest coverage was only 2.0x in 1976 and 1978, or about 75% of the industry average.

- Its earned equity returns were under 10%, about 84% of the industry average.

- PECO's average debt cost was almost 10% more than the industry. In the six years through 1975, PECO's capital growth averaged 14% more than the industry average.

- Its peak load in 1974 and 1975 dropped an average of 0.9% per year vs. increases annually averaging 4.8% over the prior five years. From 1975 through 1978, peak load increased only an average of 0.8% per year.

- The Company's Kwh sales growth declined an average of 1.5% per year in 1974 and 1975, and averaged only 2.7% per year for the 1976-78 period.

- Making matters worse, in 1976 and 1978, PECO was still faced with the completion of the Salem and Limerick generating stations.

Q. In this type of environment, what was Duff & Phelps' opinion of PECO's capital construction plans through the 1970s?

A. We were quite concerned with the large construction budgets, the high early 1970s capital growth and the outlook for no end to this financial pressure for years. Compounding the problem was the drop-off in the Company's experienced rate of load growth and peak demand, which suggested additional base load capacity would not be needed as soon as first projected. We were relieved by the 1976 and 1978 deferral announcements.

They were a common sense reaction to the financial constraints and growth trends confronting PECO in this period. These actions were the basis for our assignment of ratings which recognized that a moderating trend in capitalization growth and external financing, along with annual sales of common equity and adequate rate relief, would produce satisfactory earnings protection for senior securities in the future.

Q. Please summarize Duff & Phelps' ratings of PECO's senior debt in the 1970s.

A. A history of the changes in our ratings as well as those of Moody's and Standard & Poor's is shown in Schedule WAA-7. In late April 1976, the D&P Credit Rating Committee reassessed PECO's credit risk, and lowered the Company's bond rating to D&P-7 (Low Single A) from a 2-Medium under our prior rating scale. A 2-Medium was the fifth rating category in the prior scale. In terms of risk comparability, this was equivalent to a strong D&P-6 (Medium Single A) in the new scale. A description of the categories comprising the new scale is provided at Schedule WAA-8 to my testimony.

Q. What was the reason for the April 1976 rating reduction?

A. Our Rating Committee was concerned with PECO's ability to maintain and improve its financial ratios. Coverages for 1976 were forecast to retreat to 1974 levels, near the bottom for the D&P 5 to 7 (Single A) rated companies. Construction remained very large with the forecast at $347 million in 1976 and totaling almost $2 billion for the four years 1976-79. The Committee was concerned with whether rate increases would be adequate and also with the level of external financing which would be needed to finance PECO's capital program. I should add that this downgrading preceded the 1976 Limerick deferral announcement.

Q. What was the next rating change?

A. In our 1977 ratings, we maintained PECO at D&P-7. This was based on our evaluation of Pennsylvania regulation as Group III (average), our perception of the easing of financing pressures due to the 1976 capital expenditure reductions, and our expectation that the Company would receive adequate and timely rate relief. However, this evaluation changed the following year.

In September 1978, we again had to reduce the Company's rating due to deteriorating Pennsylvania regulation and the diminished financial flexibility of the Company. This action followed our reclassification of Pennsylvania regulation to Group IV (below average).

We were concerned with the Company's 1978 and projected earnings levels, its failure to obtain adequate interim rate relief and the resulting attrition experienced as PECO awaited rate base recognition of a major generating plant addition. There also was the prospect that this process might be repeated in 1979 when a second major unit entered service with additional negative effects on earnings.

We were particularly concerned at this time that the Company would, in the next several years, be unable to meet its mortgage bond coverage test, thus being foreclosed from issuance of mortgage bonds, and also with the fact that earnings per share were not supporting PECO's dividend, thus raising concern as to whether the dividend could be maintained in the future. By contrast, our prior decision to maintain the Company's rating in 1977 and early 1978 reflected our more positive view at that time of Pennsylvania regulation and our expectation of adequate financial performance by the Company (in substantial part due to its 1976 and 1978 capital expenditure reductions).

Q. What rating action would Duff & Phelps have taken if the Limerick schedule not been deferred in 1976 and 1978?

A. As Chairman of our Utility Rating Committee from 1974 to 1980, I recall my own and our Committee's acute concern with the Company's large capital spending and low level of coverage and internal cash generation. This was the subject of our quarterly rating review with the analyst assigned to follow PECO. I recall the construction expenditure reductions and the Company's efforts to reduce its debt ratio as key factors which tempered our evaluation of PECO's poor financial condition.

The rating reductions we made were primarily because of continued low earned returns, the Pennsylvania regulatory climate, declining coverages, and in 1980 the cost effects anticipated on nuclear plants as a result of the TMI accident and the Commission's refusal to include CWIP in rate base. Had the construction program been on its more ambitious 1975 forecast, the Company's financial ratios would have been lower. Under these circumstances, I am certain the D&P ratings would have been lowered earlier and further.

Q. Can you quantify the impact a downgrading of the Company's securities would have had upon PECO's capital costs in the period 1975 through 1982?

A. Let me first say that a further downgrading of PECO's credit rating in this period would have made the Company's ability to obtain further financing problematic, at best. In other words, I think there is a real possibility PECO would have found itself shut out of the capital markets. Having noted this qualification, if one nonetheless assumes market capacity for additional debt financing, I think it safe to say the Company would have been confronted with no less than an additional 50 to 100 basis point interest cost increase in attracting additional long-term debt financing. This would have been applicable to all of PECO's new offerings in this period.

Q. You have indicated substantial doubt that the Company would have found capacity in the market for additional financings. Please explain.

A. In the 1970s, a Triple B electric utility was regarded with extreme caution. Those companies which had sunk to that level were often shut out of the market although the Triple B category is regarded as investment grade. There were two reasons for this. First, many institutions are prohibited by law or policy from investing in securities rated below Single A. Second, during a period of concern about the industry such as existed in the 1970s, investors attempted to upgrade their holdings and at times would only buy higher (Double A) quality securities fearing that downgrades of even Single A credits would result in a Triple B holding. There was no utility "junk bond" market such as developed in 1983-84 when companies like Long Island

Lighting or Public Service of New Hampshire were able, by paying a very high price, to sell their debt instruments. Therefore, utility companies which had to have ready and frequent access to the markets strived to maintain Double A or at least strong Single A ratings.

Given PECO's condition, the prospects for earlier downgrading of its securities to a Triple B level (had it tried to pursue the additional financing needed for an accelerated completion of Limerick 1 and common) is a virtual certainty. This in turn would have made access to the capital markets highly problematic. Any debt or preferred stock sold would have been at far higher cost. Further, there is the real possibility that PECO's credit ratings would have fallen below investment grade. Given this conclusion, I believe there is real reason to question whether the Company could have proceeded with Limerick even had it attempted to do so.

Q. In his rebuttal testimony in the Limerick 1 rate case at Docket No. R-850152, Mr. Paquette supplied a hypothetical financing plan for the construction of Limerick 1 and common under an accelerated schedule which had been sponsored by one of the OCA's witnesses in that case. That schedule yielded a November 1983 commercial operation date for Limerick 1 and common (the "OKA Schedule"), and was eventually adopted by the

Commission as the basis for its decision in the Limerick 1 rate case. Have you reviewed Mr. Paquette's testimony and do you have an opinion as to the financing plan's feasibility?

A. Yes, it is my conclusion that the financing plan would not have been feasible. The plan, which indicates an additional $751.3 million of financing, is based on two critical assumptions: (1) there would be no downgrading of the Company's securities; and (2) additional rate relief would have been provided sufficient to maintain mortgage coverage ratios and historic earnings per share. We know, as a matter of historic fact, that these additional revenues were <u>not</u> received and that rate relief was extremely hard to obtain in this period. PECO's credit ratings were dropped during this period, and would have been dropped earlier and further had the ambitious OKA construction schedule been attempted. Therefore, one must conclude that the alternate financing plan discussed in the Paquette testimony simply was not "doable". Mortgage coverage ratios would not have been maintained nor would historic earnings per share have been attained. These developments would have sharply undercut the Company's ability to raise additional equity and debt capital as outlined in the alternate financing plan.

Q. In light of your comments on the Company's inability to have financed the work needed to complete Limerick 1 and common by November 1983, would you reach the same conclusion in respect of any suggestion that PECO should have proceeded with an accelerated completion of both Limerick 1 and also Limerick 2 in the period 1975 through 1982?

A. As I indicated above, if the Company had tried to complete Limerick 1 and common by November 1983, as suggested by the Commission in the Limerick 1 rate case, PECO would have been confronted with financing requirements far beyond its means. The same conclusion applies to the suggestion that the Company could have proceeded with construction of both Limerick units in that period. This would only have increased the Company's financing requirements to an even higher, more unrealistic level.

The more likely scenario is that the level of funding which Limerick 2 <u>did</u> receive in the 1975-82 period would have been substantially decreased had PECO not deferred the entire project, but instead proceeded with Limerick 1 and common. Limerick 2 work would have been reduced to the absolute minimum so that funds could be diverted to Limerick 1 and the goal of achieving the earliest possible completion date. Of course, this scenario also results in Limerick 2 being less complete than it actually was when work on it resumed under the "as-built" schedule.

I should add that this conclusion is confirmed by the Commission's own 1982 decision in the first Limerick Investigation. The Company's financial condition in 1982 was essentially the same as its condition in the period 1976 through 1978. It was on the basis of PECO's poor financial condition in 1982 that the Commission ordered a suspension of work on Unit 2, with all the Company's resources being devoted to early completion of Unit 1 and common. Of necessity, the same judgment should apply to the 1976 and 1978 deferrals. This yields two subsidiary conclusions. First, accelerated completion of either or both units in this period was never a real alternative. Second, had the Company proceeded with work on Limerick 1, this would have diverted funds away from Unit 2, leaving more work for completion following restart.

Q. Does this conclude PECO Statement No. 7?

A. Yes, it does.

PHILADELPHIA ELECTRIC COMPANY

Investor Owned Utilities
Price/Earnings Multiples
1960-1980

Year	X's
1960	22.9
1961	24.7
1962	21.8
1963	22.3
1964	22.7
1965	21.1
1966	18.8
1967	16.3
1968	16.5
1969	12.8
1970	13.5
1971	12.6
1972	11.9
1973	8.8
1974	6.4
1975	8.4
1976	9.4
1977	8.9
1978	7.6
1979	6.9
1980	6.1

Source: Duff & Phelps Twenty Company Average. (Twenty companies of the major power regions on the basis of total generating capacity and plant investment. The companies are: AEP, C&SW, Com Ed, DE, Dom R., Duke, FPL, IPALCO, MSU, NEES, NMP, NSP, PacifCorp., PS&E, PECO, PSCOLO, PSE&G, SoCo, TU, UNion Elec.)

PHILADELPHIA ELECTRIC COMPANY

Investor Owned Utilities
Selected Ratios
1970-1980

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Debt Ratio	57.1	56.9	56.0	54.7	56.8	54.7	53.4	53.2	52.2	52.9	53.0
% Incr. Avg. Cap.	12.0	13.0	13.1	12.7	14.2	11.2	8.5	9.3	8.8	11.7	10.3
Avg. Debt Int. Cost	5.3	5.5	5.7	6.0	6.7	6.9	7.1	7.3	7.5	8.0	9.0
ROE	12.2	12.0	12.2	11.8	10.4	11.5	11.6	11.5	11.8	11.4	12.0
AFC as % Bal. for Common	22	29	35	36	46	36	34	37	44	52	53
Debt Int. Cvg. Ex AFC	3.1	2.7	2.6	2.6	2.2	2.4	2.6	2.6	2.6	2.3	2.2
Mkt. to Book-Common Stock	163	150	145	102	70	96	106	100	87	77	74
Yield-Common Stock	5.28	5.47	5.61	7.70	12.15	8.42	7.71	8.16	9.85	11.49	12.51

Source: D&P Twenty Company Average

PHILADELPHIA ELECTRIC COMPANY

Selected PECO Financial Ratios 1970-1980

Year	Int. Cvg. Ex AFC	Int. Cvg. Ex AFC & Def. Fuel	Cap. Incr. %	Debt Ratio %	Avg. Int. Cost %	ROE %
1967	4.3	4.3	8.3	55.5	4.1	10.9
1968	3.5	3.5	9.2	58.2	4.5	10.3
1969	3.0	3.0	11.9	56.7	5.0	9.4
1970	2.2	2.2	16.5	56.8	5.6	10.8
1971	2.4	2.4	16.1	54.0	5.7	11.6
1972	2.4	2.4	15.2	53.3	5.9	10.3
1973	2.2	2.2	14.9	51.0	6.2	9.8
1974	1.8	1.6	14.1	54.4	7.1	8.9
1975	2.0	2.0	10.1	53.2	7.6	9.4
1976	2.1	2.1	5.8	51.6	7.7	9.9
1977	2.0	2.0	5.9	51.8	8.0	9.6
1978	1.9	2.0	5.8	52.1	8.2	9.7
1979	1.6	1.2	7.3	53.2	8.5	9.8
1980	1.5	1.8	7.0	51.8	9.5	10.6

	Avg. Realization Per Kwh	Fuel & Net purchased pr.	All Other
1970 ¢/Kwh	1.78	.44	1.34
1980 ¢/Kwh	6.32	3.07	3.25
1970-80 % Incr.	255	597	142

Source: Company Reports

PHILADELPHIA ELECTRIC COMPANY

PECO Construction Forecasts
($MM)

Date	1975	1976	1977	1978	1979	1980
5/28/75	410	469	481	550	674	
5/24/76	361A	437	414	390	478	470
4/19/77		380A	448	434	455	511
5/10/78			393A	483	418	465
4/30/79				406A	406	466
Post 1975 Reductions	49	89	88	144	268	4

1975 External Financing Forecast
($MM)

Date	1975	1976	1977	1978	1979
5/28/75	355	328	320	349	523

A - Actual

Source: Published Company Data

PHILADELPHIA ELECTRIC COMPANY

Delayed Generating Plants

Company		Plant
Long Island Lighting		Shoreham
Detroit Edison		Fermi
		Belle River
Public Serv. E&G		Hope Creek
Consumer Power		Midland
Ohio Edison	)	Beaver Valley No. 2
Cleveland Electric	)	
Toledo Edison	)	
Duquesne Light	)	
Niagara Mohawk		Nine Mile Point
Georgia Power		Plane Vogtle
		Sherer 1
Pacific P&L		Wyodok 1

Source: Annual Electric Power Survey Report of the Electric Power Survey Committee of the Edison Electric Institute

Schedule WAA-6

PHILADELPHIA ELECTRIC COMPANY

PECO Sources & Uses of Funds
1970-1980

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1992
Net Income	$ 68,376	$ 93,624	$107,974	$122,867	$129,097	$143,925	$164,618	$173,439	$184,861	$194,471	$227,131	$ 277,565	$336,2[illegible]
Less: Total AFC	18,513	31,691	42,450	58,743	70,841	66,874	77,641	86,078	90,997	113,383	147,550	188,797	213,2[illegible]
Fuel Cost Def. (Recovery)	--	--	--	--	21,655	(3,722)	1,921	3,154	(18,781)	79,285	(72,464	(42,347)	(54,080)
Less:													
Pfd. Div.	8,612	15,320	22,046	28,056	34,272	36,026	39,414	40,712	43,877	44,760	52,973	53,804	57,600
Common Div.	53,683	60,689	67,735	78,350	86,458	95,439	107,683	124,893	135,607	144,984	157,423	189,434	240,868
Balance	(12,432)	(14,076)	(24,257)	(42,282)	(84,129)	(50,692)	(62,041)	(81,398)	(66,919)	(187,941)	(58,351	(112,123)	(121,425)
Plus:													
Non-Cash Exp.	52,293	60,453	69,691	77,468	126,806	124,046	179,550	175,808	193,173	164,901	146,368	171,091	251,099
Funds From Operations	39,861	46,377	45,434	35,186	42,677	73,354	117,509	94,410	126,254	(23,040)	88,017	58,962	129,674
(Inc) Decr Other Work Cap	(3,292)	(633)	508	17,122	(68,945)	(1,690)	(38,301)	(20,279)	(5,436)	28,114	36,286	(62,144)	(9,498)
Nonrecurring Item	--	--	--	--	--	18,750	64,000	--	--	--	--	153,909	---
Net Funds	36,569	45,744	45,942	52,308	(26,268)	90,414	183,208	74,131	120,818	5,074	124,303	150,733	120,176
Construction	351,554	351,514	399,676	494,187	476,696	361,368	380,007	393,134	405,606	421,615	579,802	787,075	870,715
Less: Total AFC	18,513	31,691	42,450	58,743	70,841	66,874	77,641	86,078	90,997	113,383	147,550	188,797	213,260
Net Construction	333,041	319,823	357,226	435,444	405,855	294,494	302,366	307,056	314,609	308,232	432,252	598,278	657,455
Debt Retirement	10,140	34,838	18,130	14,290	69,313	95,193	63,271	38,945	31,472	56,169	140,671	137,470	50,183
Other	1,704	(1,867)	34,413	(29,240)	(10,093)	9,480	12,971	13,196	9,106	9,629	3,599	35,045	26,823
Total Requirement	344,885	352,794	409,769	420,494	465,075	399,167	378,608	359,197	355,137	374,030	576,522	770,793	734,461
Int % of Total	10.6	13.0	11.2	12.4	(5.6)	17.9	20.9	20.6	34.0	1.3	21.6	25.2	18.3
Int of % of Constr	11.0	14.3	12.9	12.0	(6.5)	24.3	26.2	24.1	38.4	1.6	28.8	19.6	16.4
External Financing:													
Short-term Debt	(23,262)	(26,247)	54,543	43,922	30,192	(69,970)	(100,728)	7,649	1,344	68,968	(32,597)	1.635	10,475
Long-term Debt	206,700	160,000	140,000	100,000	375,000	249,000	200,000	173,500	150,000	200,000	275,000	423.500	320,000
Pfd. Stock	65,000	70,000	75,000	75,000	75,000	--	50,000	--	50,000	--	72,000	---	30,000
Common Stock	59,878	103,297	94,204	149,264	11,151	133,723	86,128	103,917	32,975	99,988	137,816	194,925	253,810
Total	308,316	307,050	363,827	368,186	491,343	308,753	235,400	285,066	234,319	368,956	452,219	620,060	614,285

Source: Published Company Reports

PHILADELPHIA ELECTRIC COMPANY

Rating Agency Changes

	Duff & Phelps		Moody's		Standard & Poors	
	From	To	From	To	From	To
11/70			Aaa	Aa		
09/74			Aa	A	AA	A
02/76					A	A-
04/76	6*	7				
09/78	7	8				
04/80	8	9			A-	BBB+
06/81			A	Baa	BBB+	BBB
09/82					BBB	BBB-
01/83			Baa2	Baa3		

*Prior D&P rating scale stated as 2-Med.

Source: Agency Announcements

Duff and Phelps Credit Rating Scale

D&P Rating	Generic Category	Description
1	Triple A	Highest credit quality. The risk factors are negligible, being only slightly more than for risk-free U.S. Treasury debt.
	Double A	
2 3 4	High Medium Low	High credit quality. Protection factors are strong. Risk is modest but may vary slightly from time to time because of economic conditions.
	Single A	
5 6 7	High Medium Low	Protection factors are average but adequate. However, risk factors are more variable and greater in periods of economic stress.
	Triple B	
8 9 10	High Medium Low	Below average protection factors but still considered sufficient for institutional investment. Considerable variability risk during economic cycles.
	Double B	
11 12 13	High Medium Low	Below investment grade but deemed likely to meet obligations when due. Present or prospective financial protection factors fluctuate according to industry conditions or company fortunes. Overall quality may move up or down frequently within this category.
	Single B	
14 15 16	High Medium Low	Below investment grade and possessing risk that obligations will not be met when due. Financial protection factors will fluctuate widely according to economic cycles, industry conditions and/or company fortunes. Potential exists for frequent changes in quality rating within this category or into a higher or lower quality rating grade.
17	Substantial Risk	Well below investment grade with considerable uncertainty as to timely payment of interest, preferred dividends and/or principal and sinking funds. Protection factors are narrow and risk can be substantial with unfavorable economic/industry conditions, and/or with unfavorable company developments.
18-20		Reserved for later use.