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NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
CONSULTING ECONOMISTS

PECO STATEMENT NO. 29

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

DIRECT TESTIMONY OF DR. JOHN H. WILE

LIMERICK 1 AND COMMON PLANT INDEPENDENT ASSESSMENT OF LIMERICK COST AND SCHEDULE AND PRUDENCY OF PAST DECISIONS

September 27, 1985

Q. Please state your name and business address.

A. My name is John H. Wile and my business address is 123 Main Street, White Plains, New York.

Q. Who is your employer?

A. I work at National Economic Research Associates, Inc. (NERA), which was established in 1961 to offer economic consulting services with particular emphasis on regulated industries and their problems. NERA specializes in the economics of energy, the environment, antitrust and labor.

Q. Dr. Wile, what is your position at NERA?

A. I am a Senior Consultant.

Q. Would you briefly describe your educational and employment background prior to your association with NERA.

A. I received my B.A. degree in economics from California State University at Northridge in 1966 and my Ph.D. in economics from Brown University in 1971. From 1970 to 1973 I taught economics at Rensselaer Polytechnic Institute. Between 1973 and 1976, when I joined NERA, I taught economics at the State University of New York at Stony Brook.

Q. Please describe your work at NERA.

A. Since joining NERA I have directed and consulted on a variety of long-range planning, energy, environmental and transportation projects. These include analyses of the comparative economics of coal and nuclear generating plants, of the economic, energy and environmental impacts of nuclear curtailment, of the impacts of

deregulating export coal rail rates and of regional coal markets.

In addition, I have done a number of studies on the impacts of environmental legislation including the 1977 Clean Air Act Amendments. The results of my work have been presented as testimony before the Interstate Commerce Commission, the Florida Department of Environmental Regulation, the Maine Public Utilities Commission, the Pennsylvania Public Utility Commission and the Arkansas Public Service Commission. Also, I have given speeches before a number of professional groups including the National Council for Environmental Balance, the Mid-Continent Area Planning Pool, the Control Data Corporation Electric Utility Executive Seminar and the Pennsylvania Electric Association. A copy of my resume listing testimonies, publications and speeches is attached.

Q. Have any of your writings been published?

A. Yes. I have written papers that have been published in The Analysis of Regional Structure: Essays in Honour of August Losch, Journal of Urban Economics, Economic Inquiry and Urban and Social Economics in Market and Planned Economies: Policies, Planning and Development.

Q. Please list the professional organizations in which you are a member.

A. I am a member of the American Economic Association, the International Association of Energy Economists and the Association of Environmental and Resource Economists.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the linear

programming model and the key assumptions NERA used to determine whether the Limerick system and Limerick 1 were part of the least cost expansion plan for PJM.

Q. Would you please give an overview of how NERA evaluated Limerick?

A. We evaluated the Limerick system and Limerick 1 in the context of the PJM system plans as of 1973, 1976, 1978 and 1980. For each of these years, we focused on capacity needs as of the commercial operation dates for the Limerick system and Limerick 1.

Evaluating capacity needs involves comparing electricity demand with the various sources of electricity available to meet the demand. On the demand side, there are the expected peak and energy demands. On the supply side, there are several sources of electricity that can be combined to meet the demand--existing generating units, planned units and additional new capacity (generic plants). Because we were focusing only on the issue of whether Limerick is economic, we assumed that other units planned as of 1973, 1976, 1978 and 1980 would enter service as expected. Consequently, whether Limerick is part of the most economic mix for PJM depends on the operating cost and availability of the existing and the planned units, and on the capital costs, operating costs and availability of Limerick and generic capacity.

To determine whether the Limerick system and Limerick 1 were part of the least cost PJM expansion plan, we used the NERA Utility System Planning Model. This is a linear programming model that determines the mix of generating capacity that meets electricity

demand at lowest cost. In projecting this mix of capacity, the model takes into account:

1. Electricity demand--by season and load period.
2. Existing and planned generating units--their operating costs and characteristics.
3. The Limerick system and Limerick 1--their operating costs, operating characteristics and capital costs.
4. Generic capacity--its operating cost, operating characteristics and capital costs.

Q. Would you describe the basis of the demand forecasts you used in your analysis?

A. There were several steps in deriving the demand projections. First, we evaluated Limerick as of its expected commercial operation dates for each year of analysis. For the Limerick system we assumed the in-service dates to be the average dates for Units 1 and 2. The expected commercial operation dates are described in Schedule 1.

Second, to take account of transmission constraints among PJM members, we aggregated companies into four regions. These are described in Schedule 2.

Third, we developed two sets of demand projections for each expected commercial operation date. The first set of forecasts are the Expected Growth cases. These are based on the company demand forecasts for each year of analysis aggregated according to our regional definitions. The company peaks were adjusted when

aggregating them into the regional peaks to reflect non-coincidence of peak demands. The regional demand forecasts by year of analysis and expected in-service date are summarized in Schedule 3.

The other set of forecasts are the Zero Growth cases. These assumed no growth in demand beyond each year of analysis. These forecasts were used to evaluate the sensitivity of the economic benefits of Limerick to demand growth. The Zero Growth regional demands are also summarized in Schedule 3.

Q. How did you develop the demands by seasons and by load periods?

A. The first step was to define the seasons. These were derived from hourly load data for 1983. The peak demands for each month were identified. Then months with similar peak demands were grouped into seasons. Based on this analysis we defined the four seasons given in Schedule 4.

Second, we defined the load periods. This was done by grouping hourly demands within each season by the intensity of demand, from highest to lowest. This process yielded seven load periods for the peak season and from three to five load periods for the other seasons. The loads for each season and load period were then expressed as a percent of the annual peak demand. The hours in each load period are given in Schedule 5.

The third step was to determine the level of electricity demand for each load period and season for each growth case and in-service date. The shape of the load curves developed in the first two steps reflect the peak and energy demands, and therefore

the load factors, prevailing in 1983. These load curves are adjusted for the demand characteristics--peak, energy and load factor--of the forecasts for each year of analysis. When these demands reflect a load factor higher than what prevailed in 1983, the load for each period is increased relative to the peak demand. Those load periods with the lowest level of demand increase the most. If the forecasted load factor for a year of analysis is less than in 1983, the level of demand for each load period is lowered. The projected demands by season and load period for the Expected Growth cases are given in Schedule 6, and those for the Zero Growth cases are given in Schedule 7.

Q. How did you take into account the limits on transmission among PJM companies?

A. Based on data from Philadelphia Electric Company and discussions with Philadelphia Electric engineers, we grouped the companies into the four regions described in Schedule 2. The limits on transmission among regions were provided by Philadelphia Electric and are given in Schedule 8. From the point of view of transmission, Philadelphia Electric is part of the eastern region. Consequently, we assumed there were no limits on transmission between Philadelphia Electric and the East region.

Q. What are the key characteristics that determine whether Limerick should be part of the PJM least cost capacity expansion plan?

A. The key factors for Limerick are capital costs, capital additions, fuel costs, non-fuel operating and maintenance (O&M)

expenses, and maximum capacity factor. In evaluating Limerick, however, we must also consider these same factors for generic capacity as well as the operating costs of the existing and planned units on the PJM system.

Q. Would you please describe the basis for the Limerick capital costs used in your analysis?

A. We evaluated Limerick on an incremental cost basis. The incremental costs are the capital expenditures that remain to be spent after the year of analysis. Limerick's total costs, sunk costs (what had been spent through each year of analysis) and incremental costs are described in Schedule 9 of Dr. Perl's testimony.

The direct incremental capital costs were then booked using the NERA utility financial model. It is described in Dr. Perl's testimony along with the underlying accounting and financial assumptions.

Using these booked capital costs we then estimated levelized annual capital charges for the Limerick system, Limerick 1 and generic coal units. These charges include all revenues needed to amortize the plants, pay a return to investors, interest on debt and taxes. For nuclear plants, decommissioning costs are also included. In addition, they include allowances for continuing capital expenses which are associated with coal and nuclear plants.

In order to estimate the levelized annual capital charge, the NERA utility financial model was used to calculate capital-related revenue requirements for each year of plant life. We then solve

for a constant annual charge which, after adjusting for inflation, yields revenues with the same discounted present value. For convenience, we have expressed the levelized annual capital charge as a percentage of initial capital costs. This is referred to as the levelized real fixed charge rate. The fixed charge rates, along with other key characteristics for Limerick in each year of analysis are summarized in Schedule 9.

As indicated above, the estimates of levelized annual capital charges include allowances for post-commercial nuclear additions. For nuclear plants, these capital additions were estimated using a regression equation which relates capital additions to plant characteristics and to time. The regression results are given in Schedule 12 of Dr. Perl's testimony.

Q. How did you derive the O&M for Limerick?

A. For Limerick units we estimated the non-fuel O&M using a regression relating O&M expenses to unit characteristics. The fixed O&M costs as of each analysis year were based on the predictions of the regression equation as of that year. For example, the 1978 forecast was based upon prevailing O&M costs in 1978. The regression results are described in Schedule 13 of Dr. Perl's testimony.

Q. What is the basis for the availability rates used in your analysis?

A. For Limerick the expected maximum capacity factor we used declined over the course of the analysis. For the 1973 analysis, we assumed Limerick would achieve a 70 percent capacity factor.

This was based on data for small nuclear units which had achieved these capacity factors. However, during the seventies larger nuclear units came on-line and did not realize these output levels, and, consequently, expected capacity factors have declined. We have reflected these declining expectations by reducing the maximum capacity factor. From the 70 percent for the 1973 year of analysis, it declines by 1 percentage point per year so that for the 1976 year of analysis, it is 67 percent, 65 percent for 1978 and 63 percent for 1980.

Q. Did you consider any other units besides Limerick?

A. Yes, in order to determine whether Limerick was the least cost alternative we allowed the option of adding new coal (generic coal units) capacity beyond the existing planned units.

Q. What was the basis for the costs and characteristics of the generic coal units?

A. These units were assumed to consist of two 400 MW subcritical units burning a medium sulfur, 2.7 percent, bituminous coal and having a flue gas desulfurization system (scrubbers). For the 1973 and 1976 analyses we assumed the scrubbers were designed to remove about 70 percent of the sulfur to achieve an emissions rate of 1.2 pounds of sulfur dioxide per million Btu, as mandated under the 1970 Clean Air Act for new sources. Their particulate standard was assumed to be 0.10 pounds per million Btu.

For the 1978 and 1980 analyses we assumed the generic coal units would meet the 1977 Clean Air Act Amendments by removing about 90 percent of the sulfur and having a particulate system to

comply with the 0.03 pounds per million Btu standard. The costs and key characteristics for the generic coal units are summarized in Schedule 10.

The basis for the capital costs, non-fuel O&M expenses, availability factors and heat rates are described in Schedules 10, 14, 15, 16 and 19, respectively, of Dr. Perl's testimony.

Q. How did you estimate fuel costs for Limerick and generic coal units?

A. For generic coal units we developed estimates of delivered prices in two steps. First, using FERC data on the cost and quality of fuels we determined for coal with a sulfur content of at least 1.5 percent the delivered prices to eastern PJM for each year of analysis. Second, we estimated the real coal price escalation rate, 1 percent per year, using the NERA Coal Model. The 1 percent is the real escalation rate projected by the model for medium sulfur coal delivered to Pennsylvania. This model specifies supplies for 24 different coal types from 21 regions and coal demands for 21 regions of the country. It determines the prices for coals that will balance regional demands and supplies for different coal types. The coal prices and the annual real escalation rates as of each year of analysis are given in Schedule 11.

For the Limerick fuel prices we developed estimates based on the NERA Nuclear Fuel Model. The derivation of Limerick's fuel prices is described in Dr. Perl's testimony and in his Schedule 17.

Q. What did you assume about fuel prices for the existing units

in PJM?

A. Philadelphia Electric provided us with unit specific data fuel costs as of the beginning of 1983. For the nuclear fuel we developed estimates for U.S. average prices as of each year of analysis and as of the beginning of 1983. We then scaled the 1983 unit specific prices to the levels prevailing in each year of analysis. This was done by multiplying the 1983 unit prices by the ratio of the average price prevailing in a year of analysis to the average 1983 price.

For coal prices we followed a similar approach. In this case, we used historical delivered prices of medium sulfur coal to eastern PJM to develop the ratios to scale the unit specific fuel price data for beginning 1983. For oil prices we also used this approach, based on historical delivered prices to Pennsylvania, to develop these ratios.

Q. What was the basis for your assumptions about other characteristics for existing units?

A. With respect to the availability and capability of these units, we relied on the information provided by Philadelphia Electric. The key characteristics for the units are capacity, forced outage rates, maintenance requirements and heat rates.

Q. Dr. Wile, does this conclude your testimony?

A. Yes, it does.

PROJECTED COMMERCIAL OPERATION DATE FOR LIMERICK SYSTEM AND LIMERICK 1 BY YEAR OF ANALYSIS

Year of Analysis	Projected Commercial Operation Date	
	Limerick System[1,2] (1)	Limerick 1[2] (2)
1973	1980.5	1980
1976	1984	1983
1978	1986	1985
1980	1986.5	1985

Sources and Notes

[1]Limerick system commercial operation date is an average of the commercial operation dates of Limerick 1 and 2.

[2]Commercial operation date estimates were provided by PECO.

DEFINITION OF REGIONS

Region	Companies
PECO	Philadelphia Electric
East	Atlantic Electric Delmarva Power and Light Jersey Central Public Service Electric and Gas
West	Metropolitan Edison Pennsylvania Power and Light Luzerne (UGI) Pennsylvania Electric
South	Baltimore Gas and Electric Potomac Electric Power

THE 1973 DEMAND FORECAST FOR 1980 BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,332	41,600
East	17,872	82,451
West	10,874	61,144
South	10,776	48,555
PJM	47,854	233,750
Zero Growth:[2]		
PECO	5,702	27,681
East	11,827	56,088
West	6,805	40,414
South	7,111	31,833
PJM	31,445	156,016

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1974.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1976 DEMAND FORECAST FOR 1983 BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,120	41,344
East	16,495	78,758
West	10,930	62,387
South	10,346	47,822
PJM	45,891	230,311
Zero Growth:[2]		
PECO	5,607	28,433
East	11,987	56,833
West	7,485	41,748
South	7,232	32,703
PJM	32,311	159,717

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1976.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1976 DEMAND FORECAST FOR 1984 BY REGION

Region and Case	Demand Forecast Peak (MW) (1)	Demand Forecast Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,514	43,688
East	17,313	82,869
West	11,579	65,880
South	10,760	50,043
PJM	48,166	242,480
Zero Growth:[2]		
PECO	5,607	28,433
East	11,987	56,833
West	7,485	41,748
South	7,232	32,703
PJM	32,311	159,717

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1976.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1978 DEMAND FORECAST FOR 1985 BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	7,035	38,035
East	16,294	80,014
West	10,402	59,389
South	9,652	45,959
PJM	43,383	223,397
Zero Growth:[2]		
PECO	5,606	29,197
East	12,460	60,239
West	7,973	44,824
South	7,543	34,933
PJM	33,582	169,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1978.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1978 DEMAND FORECAST FOR 1986 BY REGION

Region and Case	Demand Forecast Peak (MW) (1)	Demand Forecast Generation (GWH) (2)
Expected Growth:[1]		
PECO	7,231	39,479
East	16,901	83,084
West	10,719	61,427
South	9,946	47,516
PJM	44,797	231,506
Zero Growth:[2]		
PECO	5,606	29,197
East	12,460	60,239
West	7,973	44,824
South	7,543	34,933
PJM	33,582	169,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1978.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1980 DEMAND FORECAST FOR 1985 BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	6,209	34,153
East	14,616	73,495
West	9,700	56,246
South	8,959	42,571
PJM	39,484	206,465
Zero Growth:[2]		
PECO	5,992	29,975
East	12,468	62,611
West	8,020	46,273
South	7,727	36,334
PJM	34,207	175,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1980.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1980 DEMAND FORECAST FOR 1986 BY REGION

Region and Case	Demand Forecast Peak (MW) (1)	Demand Forecast Generation (GWH) (2)
Expected Growth:[1]		
PECO	6,308	35,129
East	14,991	76,017
West	10,012	58,137
South	9,205	43,842
PJM	40,516	213,125
Zero Growth:[2]		
PECO	5,992	29,975
East	12,468	62,611
West	8,020	46,273
South	7,727	36,334
PJM	34,207	175,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1980.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

DEFINITION OF SEASONS

Season	Months
1	July, August, September
2	June
3	December, January, February
4	March, April, May, October, November

HOURS BY LOAD PERIOD AND SEASON[1]

Load Period	Season (1)	(2)	(3)	(4)
1	22	53	115	897
2	45	74	822	1,587
3	247	170	882	1,188
4	436	261	341	
5	458	162		
6	723			
7	277			
Total Hours	2,208	720	2,160	2,672

Sources and Notes

[1]Derived from the 1983 hourly load data.

THE 1973 PROJECTED ELECTRICITY DEMAND FOR 1980 (EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	8,107	17,341	9,488	10,631
	2	7,704	16,390	9,224	10,276
	3	7,052	14,851	8,743	9,315
	4	6,264	12,989	7,984	8,094
	5	5,455	11,079	7,110	6,774
	6	4,476	8,769	5,760	5,346
	7	3,508	6,482	4,695	3,885
2	1	7,034	14,806	8,923	9,188
	2	6,295	13,064	8,326	8,009
	3	5,441	11,047	7,617	6,694
	4	4,486	8,792	6,118	5,381
	5	3,452	6,350	4,831	3,872
3	1	6,090	12,759	10,061	7,388
	2	5,482	11,143	8,883	6,407
	3	4,465	8,742	7,152	5,153
	4	3,653	6,825	5,755	4,046
4	1	5,319	10,757	8,340	6,030
	2	4,498	8,821	6,914	5,010
	3	3,452	6,352	5,218	3,650

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1974) and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1983
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	7,906	16,024	9,574	10,211
	2	7,524	15,180	9,316	9,879
	3	6,906	13,815	8,846	8,982
	4	6,157	12,163	8,104	7,841
	5	5,390	10,470	7,249	6,609
	6	4,461	8,420	5,929	5,276
	7	3,542	6,391	4,888	3,911
2	1	6,888	13,776	9,022	8,863
	2	6,187	12,230	8,438	7,762
	3	5,377	10,441	7,745	6,534
	4	4,470	8,441	6,279	5,308
	5	3,489	6,274	5,020	3,899
3	1	5,992	11,799	10,135	7,182
	2	5,415	10,526	8,983	6,266
	3	4,450	8,396	7,290	5,095
	4	3,680	6,696	5,923	4,061
4	1	5,260	10,184	8,452	5,914
	2	4,482	8,466	7,058	4,962
	3	3,489	6,276	5,399	3,692

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1976) and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1984
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	8,293	16,820	10,134	10,620
	2	7,896	15,937	9,859	10,278
	3	7,254	14,508	9,358	9,351
	4	6,478	12,780	8,567	8,173
	5	5,682	11,008	7,656	6,901
	6	4,719	8,863	6,249	5,523
	7	3,766	6,740	5,140	4,114
2	1	7,236	14,467	9,546	9,229
	2	6,509	12,850	8,923	8,091
	3	5,669	10,977	8,184	6,823
	4	4,729	8,884	6,622	5,557
	5	3,710	6,617	5,281	4,101
3	1	6,307	12,399	10,732	7,492
	2	5,708	11,066	9,504	6,546
	3	4,708	8,838	7,700	5,336
	4	3,909	7,058	6,243	4,269
4	1	5,548	10,709	8,938	6,182
	2	4,741	8,911	7,452	5,199
	3	3,711	6,619	5,685	3,887

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, (June 1, 1976) and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1985
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,866	15,845	9,112	9,530
	2	6,563	15,040	8,867	9,231
	3	6,073	13,737	8,419	8,422
	4	5,480	12,161	7,714	7,394
	5	4,873	10,545	6,901	6,283
	6	4,137	8,590	5,645	5,081
	7	3,409	6,654	4,654	3,851
2	1	6,059	13,699	8,587	8,315
	2	5,504	12,224	8,032	7,323
	3	4,862	10,518	7,372	6,216
	4	4,144	8,609	5,978	5,111
	5	3,367	6,542	4,781	3,840
3	1	5,350	11,814	9,646	6,800
	2	4,893	10,599	8,550	5,974
	3	4,129	8,567	6,939	4,918
	4	3,518	6,944	5,640	3,986
4	1	4,770	10,272	8,045	5,656
	2	4,154	8,634	6,718	4,798
	3	3,368	6,544	5,141	3,653

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1986
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	7,060	16,435	9,399	9,821
	2	6,754	15,602	9,148	9,514
	3	6,258	14,252	8,690	8,694
	4	5,658	12,620	7,968	7,629
	5	5,044	10,946	7,136	6,488
	6	4,300	8,921	5,851	5,254
	7	3,563	6,916	4,838	3,992
2	1	6,244	14,213	8,862	8,574
	2	5,683	12,686	8,293	7,555
	3	5,033	10,918	7,618	6,419
	4	4,307	8,941	6,192	5,285
	5	3,520	6,800	4,967	3,980
3	1	5,526	12,260	9,945	7,018
	2	5,064	11,002	8,823	6,171
	3	4,291	8,897	7,176	5,087
	4	3,674	7,216	5,846	4,131
4	1	4,940	10,664	8,307	5,845
	2	4,316	8,966	6,950	4,964
	3	3,521	6,801	5,335	3,789

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1985
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,064	14,225	8,533	8,846
	2	5,804	13,525	8,310	8,567
	3	5,384	12,392	7,905	7,814
	4	4,875	11,022	7,267	6,858
	5	4,354	9,617	6,530	5,825
	6	3,723	7,917	5,393	4,706
	7	3,098	6,233	4,497	3,561
2	1	5,372	12,360	8,057	7,715
	2	4,896	11,077	7,554	6,792
	3	4,345	9,593	6,957	5,762
	4	3,729	7,934	5,695	4,733
	5	3,062	6,136	4,611	3,551
3	1	4,763	10,720	9,015	6,305
	2	4,371	9,663	8,023	5,536
	3	3,716	7,897	6,565	4,554
	4	3,192	6,486	5,389	3,687
4	1	4,266	9,380	7,566	5,241
	2	3,737	7,955	6,366	4,442
	3	3,063	6,137	4,937	3,377

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1980) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1986
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,164	14,595	8,810	9,089
	2	5,905	13,885	8,582	8,804
	3	5,487	12,736	8,165	8,032
	4	4,982	11,347	7,507	7,052
	5	4,463	9,922	6,750	5,993
	6	3,835	8,198	5,579	4,847
	7	3,214	6,491	4,656	3,675
2	1	5,475	12,703	8,321	7,931
	2	5,002	11,403	7,803	6,984
	3	4,454	9,898	7,189	5,929
	4	3,842	8,215	5,889	4,875
	5	3,178	6,392	4,774	3,664
3	1	4,870	11,041	9,307	6,486
	2	4,480	9,969	8,286	5,698
	3	3,828	8,178	6,786	4,692
	4	3,307	6,747	5,574	3,803
4	1	4,375	9,682	7,816	5,396
	2	3,850	8,237	6,580	4,577
	3	3,179	6,394	5,110	3,486

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1980) and the hourly load data for 1983.

1973 ELECTRICITY DEMAND FOR 1980
(NO GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,542	11,486	6,025	7,015
	2	5,257	10,877	5,876	6,779
	3	4,794	9,890	5,605	6,140
	4	4,235	8,696	5,179	5,329
	5	3,661	7,472	4,687	4,452
	6	2,967	5,990	3,927	3,503
	7	2,279	4,524	3,328	2,533
2	1	4,781	9,861	5,707	6,056
	2	4,257	8,744	5,371	5,273
	3	3,651	7,451	4,972	4,399
	4	2,974	6,005	4,128	3,527
	5	2,240	4,439	3,404	2,524
3	1	4,111	8,433	6,347	4,860
	2	3,680	7,512	5,684	4,208
	3	2,959	5,973	4,710	3,375
	4	2,383	4,744	3,924	2,639
4	1	3,564	7,265	5,379	3,958
	2	2,982	6,025	4,577	3,280
	3	2,240	4,440	3,622	2,376

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1974, and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1983 AND 1984
(NO GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,459	11,642	6,517	7,135
	2	5,193	11,024	6,333	6,898
	3	4,764	10,023	5,997	6,255
	4	4,244	8,813	5,467	5,439
	5	3,711	7,572	4,857	4,557
	6	3,066	6,070	3,914	3,602
	7	2,428	4,583	3,170	2,625
2	1	4,751	9,994	6,123	6,170
	2	4,265	8,861	5,706	5,382
	3	3,702	7,550	5,210	4,503
	4	3,073	6,085	4,164	3,625
	5	2,391	4,497	3,265	2,616
3	1	4,130	8,546	6,917	4,967
	2	3,729	7,613	6,094	4,311
	3	3,059	6,052	4,886	3,472
	4	2,524	4,806	3,910	2,733
4	1	3,621	7,362	5,715	4,059
	2	3,081	6,103	4,720	3,377
	3	2,391	4,498	3,536	2,467

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1976, and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1985 AND 1986
(NO GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,463	12,110	6,956	7,445
	2	5,208	11,482	6,763	7,203
	3	4,794	10,466	6,410	6,550
	4	4,294	9,237	5,854	5,721
	5	3,781	7,977	5,212	4,825
	6	3,160	6,452	4,222	3,854
	7	2,546	4,943	3,441	2,862
2	1	4,782	10,437	6,542	6,464
	2	4,314	9,287	6,104	5,663
	3	3,772	7,955	5,584	4,770
	4	3,166	6,467	4,485	3,878
	5	2,510	4,855	3,541	2,853
3	1	4,184	8,966	7,377	5,241
	2	3,798	8,019	6,512	4,575
	3	3,153	6,435	5,243	3,723
	4	2,638	5,169	4,218	2,971
4	1	3,694	7,764	6,114	4,139
	2	3,174	6,486	5,069	3,626
	3	2,511	4,857	3,825	2,702

Sources and Notes

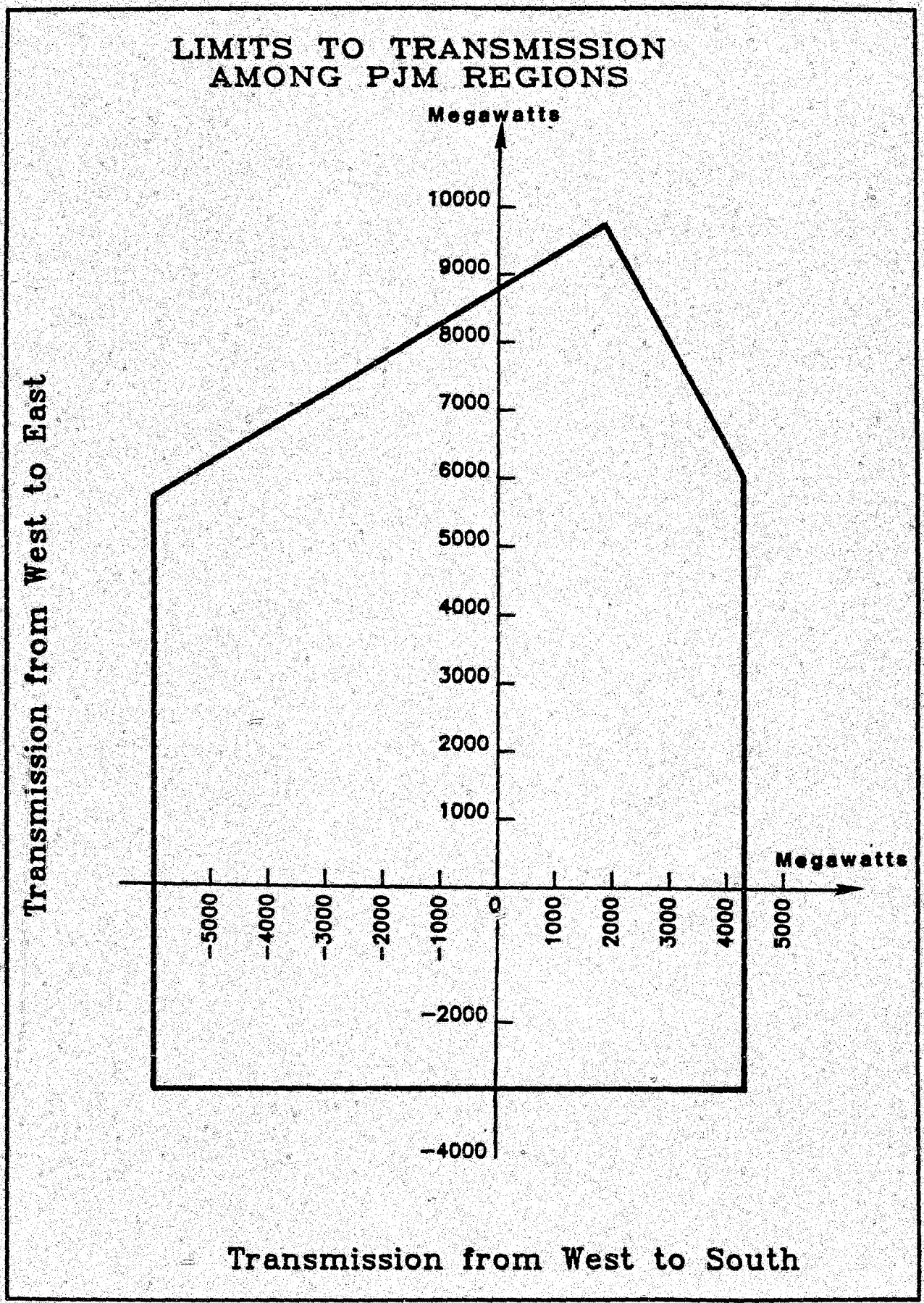
[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1985 AND 1986 (NO GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,831	12,134	7,045	7,628
	2	5,542	11,536	6,860	7,385
	3	5,074	10,568	6,522	6,728
	4	4,508	9,397	5,988	5,893
	5	3,928	8,196	5,374	4,990
	6	3,226	6,743	4,425	4,013
	7	2,532	5,304	3,676	3,014
2	1	5,061	10,540	6,648	6,641
	2	4,531	9,444	6,228	5,835
	3	3,918	8,175	5,730	4,935
	4	3,233	6,757	4,676	4,037
	5	2,491	5,221	3,772	3,005
3	1	4,385	9,139	7,448	5,410
	2	3,948	8,236	6,620	4,739
	3	3,218	6,726	5,403	3,881
	4	2,636	5,520	4,421	3,124
4	1	3,820	7,993	6,238	4,481
	2	3,242	6,776	5,236	3,783
	3	2,492	5,222	4,044	2,853

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1980, and the hourly load data for 1983.


LIMITS TO TRANSMISSION
AMONG PJM REGIONS
Megawatts
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
Megawatts
-5000
-4000
-3000
-2000
-1000
0
1000
2000
3000
4000
5000
-2000
-4000
Transmission from West to East
Transmission from West to South

EXPECTED CHARACTERISTICS OF LIMERICK SYSTEM AND LIMERICK 1

	Limerick 1				Limerick System			
	1973 (1)	1976 (2)	1978 (3)	1980 (4)	1973 (5)	1976 (6)	1978 (7)	1980 (8)
Capital Cost (Mid-84 $/kW)[1]	603	640	542	397	555	705	606	623
Real Levelized Fixed Charge Rate (Percent)[2]	6.4	5.8	5.9	6.5	6.4	5.9	6.0	6.7
Levelized Fixed O&M (Mid-84 $/kW)[3]	13.91	21.36	26.99	37.01	10.43	16.01	20.23	27.75
Levelized Capital Additions (Mid-84 $/kW)[4]	2.59	5.31	8.82	18.31	1.98	4.05	6.72	13.95
Equivalent Forced Outage Rate (Percent)[5]	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Hours of Maintenance Per Year (Hours)[6]	582	932	1,165	1,398	582	932	1,165	1,398
Maximum Capacity Factor (Percent)[7]	70	67	65	63	70	67	65	63
First Year Fuel Cost (Mid-84 $/MMBTU)[8]	0.683	1.302	1.335	1.119	0.684	1.316	1.348	1.130

Sources and Notes

[1]The booked cost per kilowatt of Limerick 1 and Limerick system as of the projected on-line date. This estimate includes all construction costs through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11 of Dr. Perl's testimony. For the derivation of construction costs see Schedule 9 of Dr. Perl's testimony. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit deflator was used to measure price changes and is given in Schedule 11 of Dr. Perl's testimony. Expected inflation is also shown in Schedule 11.

The projected commercial operation dates by year of analysis for Limerick 1 and Limerick plant can be found in Schedule 1.

EXPECTED CHARACTERISTICS OF LIMERICK SYSTEM AND LIMERICK 1

Sources and Notes

[2]The real levelized fixed charge rate is the annual fraction which, when applied to the initial plant investment, will yield sufficient revenues over the life of the project to cover all capital-related expenses—depreciation, interest expense, return on invested capital and taxes. It is equal to the annual capital cost, found in Schedule 8 of Dr. Perl's testimony, divided by the booked cost.

[3]The levelized annual non-fuel operation and maintenance cost in mid-1984 dollars per kilowatt. The derivation is described in Schedule 13 of Dr. Perl's testimony.

[4]The levelized annal cost of capital additions occurring over the plant's operating lifetime, in mid-1984 dollars per kilowatt. The derivation is described in Schedule 12 of Dr. Perl's testimony.

[5]The equivalent forced outage rate represents the probability the plant will not operate during the time it is not undergoing maintenance. Based on NERA assumptions.

[6]The hours of maintenance per year is one minus the capacity factor divided by the utilization rate, multiplied by the number of hours in the year (8760). The utilization rate represents the probability the plant will operate during the time it is not undergoing maintenance and is based on NERA assumptions.

[7]The projected levelized capacity factor of Limerick 1 and Limerick system. The estimate was derived, as discussed in the text, from a combination of engineering and statistical data.

[8]The levelized annual cost of fuel for Limerick in dollars per million Btu. The prices assumed for each nuclear fuel cycle component as of each analysis year are reported in Schedule 17 of Dr. Perl's testimony.

EXPECTED CHARACTERISTICS OF GENERIC COAL PLANTS[1]

	1973 (1)	1976 (2)	1978 (3)	1980 (4)
Capital Cost (Mid-84 $/kW)[2]	840	1,097	1,198	1,405
Real Levelized Fixed Charge Rate (Percent)[3]	6.9	6.3	6.4	7.3
Levelized Fixed O&M (Mid-84 $/kW)[4]	13.88	15.31	16.19	16.84
Equivalent Forced Outage Rate (Percent)[5]	19.00	19.00	19.00	19.00
Hours of Maintenance Per Year (Hours)[6]	1,203	1,774	1,772	1,744
Maximum Capacity Factor (Percent)[7]	70	65	65	65
First Year Fuel Cost (Mid-84 $/MMBtu)[8]	1.794	1.906	1.900	1.997

Sources and Notes

[1]The costs and characteristics are for a coal plant with two 400 MW units.

[2]The booked cost per kilowatt of the coal alternative as of the projected on-line date. This estimate includes all construction costs through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11 of Dr. Perl's testimony and construction costs are derived in Schedule 10. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit deflator was used to measure price changes and is given in Schedule 11 of Dr. Perl's testimony. Expected inflation is also shown in Schedule 11.
The projected commercial operation dates for the coal alternative to Limerick system by year of analysis can be found in Schedule 1.

EXPECTED CHARACTERISTICS OF GENERIC COAL PLANTS[1]

Sources and Notes

[3]The real levelized fixed charge rate is the annual fraction which, when applied to the initial plant investment, will yield sufficient revenues over the life of the plant to cover all capital-related expenses -- depreciation, interest expense, return on invested capital and taxes. It is equal to the annual cost, found on page 5 of Schedule 8 of Dr. Perl's testimony, divided by the booked cost.

[4]The levelized annual revenue requirements associated with fixed non-fuel operating and maintenance costs, expressed in mid-1984 dollars per kilowatt. The derivation of O&M cost is described in Schedule 14 of Dr. Perl's testimony.

[5]The equivalent forced outage rate represents the probability the plant will not operate during the time it is not undergoing maintenance. Based on NERA assumptions.

[6]The hours of maintenance per year is one minus the capacity factor divided by the utilization rate, multiplied by the number of hours in the year (8,760). The utilization rate represents the probability the plant will operate during the time it is not undergoing maintenance and is based on NERA assumptions.

[7]The levelized capacity factor is 93 percent of the projected equivalent availability. This derivation is described in Schedule 16 of Dr. Perl's testimony. The forecast for each analysis year was based only on units operating in that year.

[8]Coal price data reflect the average cost of coal with a sulfur content greater than 2.7 percent delivered to the Eastern PJM region in each year. Cost data are taken from FERC Form 423.

HISTORIC COAL AND OIL PRICES
BY YEAR OF ANALYSIS

Year of Analysis	Oil Price[1] (Mid-84 $/MMBTU) (1)	Coal Price[2] (Mid-84 $/MMBTU) (2)
1973	2.925	1.272
1976	3.498	1.765
1978	3.877	1.819
1980	6.015	1.879

Sources and Notes

[1]Nominal prices for the Mid-Atlantic region were taken from FERC Form 423. The prices were then brought forward to 1984 dollars using actual inflation rates.

[2]Nominal prices for the Mid-Atlantic region were taken from the Statistical Year Book of the Electric Utility Industry. The coal price was converted to dollars per million Btu using heat contents of 11851, 11923, 11931 and 12076 Btu/lb. for the years 1973, 1976, 1978 and 1980 respectively. The prices were then brought forward to 1984 dollars using actual inflation rates.

REAL ESCALATION RATES FOR OIL AND COAL PRICES BY YEAR OF ANALYSIS[1]

Year of Analysis	Oil Price (Percent) (1)	Coal Price (Percent) (2)
1973	1.0	1.0
1976	1.0	1.0
1978	1.0	1.0
1980	2.0	1.0

[1]Based on NERA assumptions.

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BROWN UNIVERSITY
Ph.D., Economics, 1971
Dissertation Title: "The Effect of Technical Change on the Location Distribution of an Industry with Application to the Fertilizer Industry"

CALIFORNIA STATE UNIVERSITY
B.A., Economics, 1966

PROFESSIONAL EXPERIENCE:

6/1976-Present

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC. (NERA)

As a Senior Consultant, Dr. Wile has directed and consulted on a variety of long range planning, energy, environmental and transportation projects. Most recently he participated in a study for the Public Service Commission of Indiana which compared the economic and financial impacts of completing the Marble Hill nuclear plant with those for various alternatives. In response to the Three Mile Island accident, Dr. Wile conducted the first study on the economic, energy and environmental effects of curtailing nuclear power. The impacts of deregulating export coal rail rates on world coal prices and shipments were the subject of another study, the results of which appeared in a New York Times editorial. He has directed many studies on the economic and energy implicatons of environmental regulations and proposals including provisions of the Clean Air and Clean Water Acts. Other studies involve the effects on the electric utility industry of deregulating natural gas.

Dr. Wile designed models used in these studies including the NERA World Coal Model and the NERA Electric Utility System Planning Model. These models and results from them have also been used in analyses conducted by others at NERA.

In addition, Dr. Wile developed the NERA Regional Electricity Price Forecasting Model.

As an expert witness, Dr. Wile has testified before regulatory agencies such as the Interstate Commerce Commission and the Maine Public Utilities Commission. He has also addressed professional groups including the National Council for Environmental Balance, Mid-Continent Area Planning Pool and the Control Data Corporation Electric Utility Executive Seminar. Attached is a list of his publications, reports and testimonies.

1973-1976 STATE UNIVERSITY OF NEW YORK AT STONY BROOK—New York
Assistant Professor
Taught graduate and undergraduate courses in urban economics and mathematics for economists in the Department of Economics and W. Averill Harriman College of Urban and Policy Sciences.

1970-1973 RENSSELAER POLYTECHNIC INSTITUTE—Troy, New York
Assistant Professor
Taught industrial organization, mathematical economics and economic theory.

PUBLICATIONS:

"Prospects for International Trade in Coal," n/e/r/a Topics, 1982.

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Improved Productivity in Planning the Need for New Generating Capacity," presented at the Control Data Corporation Electric Utilities Executive Seminar, Minneapolis, Minnesota, June 24, 1982.

"Economic, Energy and Environmental Impacts of the Clean Air Act and Its Amendments" presented at the Clean Air Act Conference sponsored by the National Council for Environmental Balance, Inc., Hartford, Connecticut, July 1, 1981.

"Some Implications on the Electric Utility Industry of An Inadequate Allowed Rate of Return," presented before the Fourth Annual Energy Conference sponsored by Energy Magazine, New York, November 24, 1980.

"The Economic, Energy and Environmental Consequences of Alternative Nuclear Growth Scenarios," presented at INFO '80 Atomic Industrial Forum, Inc., Boston, Massachusetts, February 25, 1980.

"The Impacts of Revisions to New Source Performance Standards on the Mid-Continent Area Power Pool," presented at the Mid-Continent Area Power Pool Meeting on Planning and Managing Environmental Compliance, November 8, 1978.

"Open Spaces, Revenue Sharing and Urban Structure," North American Regional Science Association Meetings, Toronto, Ontario, November 1976.

"The Impacts on Welfare and Urban Structure of Conversion from the Property to the Income Tax," Econometric Society Winter Meetings, Dallas, Texas, December 1975.

"The Impact of Demand and Cost Changes on the Spatial Dispersion of a Market Oriented Industry," Second Advanced Studies Institute on Recent Developments in Regional Science, Karlsruhe, Germany, July-August 1972.

"The Effect of Technical Change on the Distribution of an Industry with an Application to the Fertilizer Industry," North American Regional Science Association Meetings, Ann Arbor, Michigan, November 1971.

OTHER PAPERS:

"The Impacts on Welfare and Urban Structure of Conversion from the Property to the Income Tax"

with Michael Nienhaus, "Comparative Statics, Comparative Dynamics and Long-run Equilibrium with an Application to a Loschian Model"

"The Impacts of Several Energy-Saving Policies on Energy Consumption and Urban Structure: A Numerical Analysis"

"On the Interaction Between Local Government and Urban Location"

"Pure Local Public Goods, City Size and Taxation Revisited"

OCA Exhibit 61
12/16/85 Hbg PK

Q. IR-OCA-15-8 Please reference IR-OCA-2-25. Please confirm that the following annual fossil fuel price escalation rates were used in the Company's analysis:

a. Coal:

1987	7 percent increase
1988 and beyond	8 percent increase

b. No. 6 1% Sulfur Oil:

1987	8 percent increase
1988 and beyond	9 percent increase

c. No. 2 Oil:

1987	9.1 percent increase
1988 to 1990	10.7 percent increase
1991 and beyond	9 percent increase

d. Natural Gas is the same as No. 6 1% Oil.

e. No. 6 0.5% Sulfur Oil:

1987	7.9 percent increase
1988 and beyond	9 percent increase

f. Nuclear:

1987 to 1989	0 percent increase
1990 and beyond	6 percent increase

A. IR-OCA-15-8 The above escalation rates for the fossil fuel units are those used in the Limerick life cycle analysis. The escalation rates for nuclear fuel are assigned on a nuclear unit basis and are provided in the production cost runs supplied in response to IR-OCA-2-25.

Responsible Witnesses: W. Hieronymus, Putnam, Hayes and Bartlett
T.P.Hill,Jr.,Asst. Manager-Rate Division

12/18/85 Hog TX

Q.IR-OCA-18-17 Please provide a schedule of capacity deficiency charges (per-kW-yr) by PJM for each year from 1970 through the present.

A.IR-OCA-18-17 The capacity deficiency rates of PJM as filed with FERC are:

Period	$/KW Yr.
1970	10.40
1971	11.44
1972	12.48
1973	12.48
1/1/74 to 5/31/74	12.48
6/1/74 to 5/31/75	14.60
6/1/75 to 5/31/76	16.425
6/1/76 to 5/31/77	18.25
6/1/77 to 5/31/78	20.075
6/1/78 to 5/31/79	22.63
6/1/79 to 5/31/80	25.55
6/1/80 to 5/31/81	28.105
6/1/81 to 5/31/82	30.66
6/1/82 to 5/31/83	36.865
6/1/83 to 5/31/84	47.45
6/1/84 to 5/31/85	52.93
6/1/85 to 5/31/86	52.93

Responsible Witness: J. J. Carroll, Staff Engineer, Services Division

DOCKET NO. R-850152

12/16/85

Q. IR-OCA-9-12. What does PJM charge a member utility for each kW by which its generation capacity falls short of its PJM-determined reserve requirement? What is the pricing basis for this per-kW charge?

A. IR-OCA-9-12. The most recently adopted capacity rate for use in determining charges associated with an installed capacity deficiency of a PJM member company during the 1985-1986 planning period is $145 per MW-Day which equates to $52.93 per kW-year. This rate is based on the levelized carrying charge for an average new 50 MW combustion turbine installed in PJM.

Responsible Witness: C.H. Rush, Chief Engineer - Research and Planning Division

DOCKET NO. R-850152

12/16/85 14bg
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

LIMERICK NUCLEAR GENERATING

STATION INVESTIGATION

I-80100341

INITIAL DECISION

OF

JOSEPH J. KLOVEKORN

Administrative Law Judge

March 26, 1982

TABLE 11

ANNUAL PEAK LOAD AND INSTALLED GENERATING CAPACITY FORECAST

Year			Philadelphia Electric Company Installed Generating Capacity-Mw	Estimated Peak Load Mw	Reserves %	PJM Interconnection Installed Generating Capacity-Mw	Estimated Peak Load Mw	Reserves %
1980			7968	5800	33	44774	31180	34.9
1981	- 88 mw:	Retire Chester 566	7566	5900	28		34090	34.0
	- 38 mw:	Retire Barbados 667						
	- 6 mw:	Retire Diesels (2)						
1982	- 30 mw:	Retire Schuylkill 9	7521	6000	25	46876	35090	33.6
	- 15 mw:	Derate Schuylkill 3						
1983	- 25 mw:	Cromby 1 & Eddystone 502	7490	6100	23	47882	36070	32.7
	- 6 mw:	Cromby Cooling Towers						
1984								
1985	+1055 mw:	Limerick 1 (4/85)	8539	6300	36	50826	38030	33.6
	- 471 mw:	Retire Misc. CT's & Diesels						
	- 1 mw:	Cromby 2 502						
	+ 474 mw:	Salem 2						
1986			8539	6400	33	51024	39000	30.8
1987			8539	6500	31	53271	39950	33.3
1988	+1055 mw:	Limerick 2 (10/87)	9067	6600	37	54090	40810	32.5
	- 156 mw:	Retire Southwark 162						
	- 166 mw:	Retire Richmond 9						
	- 5 mw:	Retire Diesels (2)						
1989			9067	6700	35	54020	41720	29.5
1990			9067	6800	33	55274	42650	29.6
1991			9067	6900	31	55891	43580	28.2
1992			9067	7000	30	55618	44510	25.0
1993			9067	7100	28	56785	45480	24.9
1994	+ 800 mw:	Unassigned 2	9136	7200	27	57790	46420	24.5
	- 731 mw:	Miscellaneous retirements						

OCA EXHIBIT NO. 38

DOCKET NO. R-850152

12/16/85 11:08 DD

Q. IR-OCA-2-22. Regarding the Southwark units and the 458 MW of combustion turbines scheduled for retirement in 1985, please provide:

a. the full- and part-load heat rates for each unit, currently and annually beginning in 1980;

b. the price per million BTU of fuel for the units at the present time and on a monthly basis beginning in January 1984;

c. variable non-fuel operation and maintenance (O&M) costs for the units, in cents per kWh, currently and annually beginning in 1980;

d. fixed non-fuel O&M costs for the units, in dollars per kW per year, currently and annually beginning in 1980;

e. available hours (AH), equivalent forced partial outage hours (EFOH), equivalent scheduled partial outage hours (ESOH), period housrs (PH), and equivalent availability factor (EAF), as these terms are generally used in utility industry availability data bases (e.g., those complied by EEI or NERC), currently and annually beginning in 1980;

f. a listing of the cost, nature and time requirements for all capital investments and operating expenditures that would be entailed in extending the lives of the units through approximately 1996.

A. IR-OCA-2-22. a. Attachment IR-OCA-2-22 Schedule 1 contains the information requested. The following notes apply to this information:

1. Diesels and combustion turbines operate at full load only, consequently, the information provided contains only full load values.
2. Individual diesel unit heat rates are not calculated. The diesel heat rate provided is representative of the system heat rate for this type of unit.
3. The Richmond and Plymouth Meeting heat rates reflect the system performance for the aircraft type gas turbines.

b. Attachment IR-OCA-2-22 Schedule 2 contains the information requested.

c&d.

Philadelphia Electric Company does not segregate O&M costs into variable and fixed. However, PJM member companies agreed to follow guidelines for developing incremental maintenance costs for uniformity in energy dispatching and accounting. The incremental maintenance calculated by these guidelines are tabulated on IR-OCA-2-22 Schedule 1.

The Southwark 1, 2 incremental maintenance costs utilize data for the previous 7 years reported in present year dollars.

The reported values for 1980 for the gas turbines and diesels were calculated in the same manner as explained above for Southwark 1 & 2.

Starting in 1981 the PJM changes the guidelines as follows:

Combustion turbine incremental maintenance shall reflect data for the years starting with 1970 and continuing through the year prior to the reporting year, all expressed in current year dollars.

e. Attachment IR-OCA-2-22e provides the requested data.

f. The estimated costs for the 15 year life extension of the Southwark 1 & 2 units were based on the weighted average in $/kW of the values developed for Cromby 2, Delaware 7 & 8 and Schuylkill 1 units. This direct cost in 1985 dollars and excluding AFUDC was $201.7/kW or $72 million for a January 1986 service date for Southwark. The life extension costs for the 458 mw of combustion turbines are described in Attachment IR-OCA-2-22(f).

Responsible Witness: C.H.Rush, Chief Eng.,Research & Planning Div.
J.J.Carroll,Staff Engineer-Services Division

Attachment IR-OCA-22(F)
7 Pages

CT DATA FOR LIFE EXTENSION OF 458MW OF CT'S AT RICHMOND & PLYMOUTH MEETING

1. SOBIG PRODUCTION COST DATA
2. O&M
3. CAPITAL COSTS

TABLE 3

```
1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
         1         2         3         4         5         6         7         8

208 DATA CARD  DELAFH11    6        13   2 54 1983      .385  1.0 6.413  182      7.8726PE
209 DATA CARD  11983   3    13 1398                                               3
210 DATA CARD          1
211 DATA CARD  DELAFH12    6        13   2 54 1982      .385  1.0 6.413  182      7.8726PE
212 DATA CARD  11983   3    13 1398                                               3
213 DATA CARD          1
214 DATA CARD  SCHUPH10    6        14   2 54 1982      .444  1.0 6.413  196      7.8726PE
215 DATA CARD  11983   3    14 1398                                               3
216 DATA CARD          1
217 DATA CARD  SCHUPH11    6        14   2 54 1982      .108  1.0 6.413  196      7.0726PE
218 DATA CARD  11983   3    14 1364                                               3
219 DATA CARD          1
220 DATA CARD  CROYGE11    6        39   2 14 1983      .396  1.0 6.037  386      5.2426PE
221 DATA CARD  11983   3    39  992                                               3
222 DATA CARD          1
223 DATA CARD  CROYGE12    6        39   2 14 1983      .396  1.0 6.037  386      5.2426PE
224 DATA CARD  11983   3    39  992                                               3
225 DATA CARD          1
226 DATA CARD  CROYGE21    6        45   2 14 1983      .396  1.0 6.037  449      4.6226PE
227 DATA CARD  11983   3    45  998                                               3
228 DATA CARD          1
229 DATA CARD  CROYGE22    6        34   2 14 1983      .396  1.0 6.037  369      5.2426PE
230 DATA CARD  11983   3    34 1086                                               3
231 DATA CARD          1
232 DATA CARD  CROYGE31    6        39   2 14 1983      .396  1.0 6.037  386      5.2426PE
233 DATA CARD  11983   3    39  992                                               3
234 DATA CARD          1
235 DATA CARD  CROYGE32    6        45   2 14 1983      .396  1.0 6.037  449      4.6226PE
236 DATA CARD  11983   3    45  998                                               3
237 DATA CARD          1
238 DATA CARD  CROYGE41    6        39   2 14 1983      .396  1.0 6.037  386      5.2426PE
239 DATA CARD  11983   3    39  992                                               3
240 DATA CARD          1
241 DATA CARD  CROYGE42    6        45   2 14 1983      .396  1.0 6.037  449      4.6226PE
242 DATA CARD  11983   3    45  998                                               3
243 DATA CARD          1
244 DATA CARD  RICHGE81    6        50   2 55 1981      .288  1.0 6.031  613      2.7326PE
245 DATA CARD  11983   3    50 1227                                               3
246 DATA CARD          1
247 DATA CARD  RICHGE91    6        50   2 55 1982      .288  1.0 6.031  613      2.7326PE
248 DATA CARD  11983   3    50 1227                                               3
249 DATA CARD          1
250 DATA CARD  RICHGE92    6        50   2 55 1983      .288  1.0 6.031  613      2.7326PE
251 DATA CARD  11983   3    50 1227                                               3
252 DATA CARD  .0      1
253 DATA CARD  RICHHE41    6        21   2  2 1979      .341  1.0 6.031  304      4.5126PE
254 DATA CARD  11983   3    21 1445                                               3
255 DATA CARD          1
256 DATA CARD  RICHHE42    6        21   2  2 1980      .341  1.0 6.031  304      4.5126PE
257 DATA CARD  11983   3    21 1445                                               3
258 DATA CARD          1
259 DATA CARD  RICHHE43    6        21   2  2 1981      .341  1.0 6.031  304      4.5126PE

1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
         1         2         3         4         5         6         7         8
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DATA FOR [illegible]
[illegible] PLYMOUTH [illegible]
AS SHOWN [illegible] 12/[illegible]
IN CASE 3A (TABLE 3A)

[illegible]
[illegible]

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1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
          1         2         3         4         5         6         7         8

260 DATA CARD    11983  3    21 1445                                                              3
261 DATA CARD           1
262 DATA CARD    RICHHE44    6         21   2  2 1982       .341  1.0 6.031  304              4.5126PE
263 DATA CARD    11983  3    21 1445                                                              3
264 DATA CARD           1
265 DATA CARD    RICHHE71    6         21   2  2 1983       .341  1.0 6.031  304              4.5126PE
266 DATA CARD    11983  3    21 1445                                                              3
267 DATA CARD           1
268 DATA CARD    RICHHE72    6         21   2  2 1979       .341  1.0 6.031  304              4.5126PE
269 DATA CARD    11983  3    21 1445                                                              3
270 DATA CARD           1
271 DATA CARD    RICHHE73    6         21   2  2 1980       .341  1.0 6.031  304              4.5126PE
272 DATA CARD    11983  5    21 1445                                                              5
273 DATA CARD           1
274 DATA CARD    RICHHE74    6         21   2  2 1981       1.0   1.0 6.031  304              4.5126PE
275 DATA CARD    11983  3    21 1445                                                              3
276 DATA CARD           1
277 DATA CARD    RICHWO21    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
278 DATA CARD    11983  3    31 1473                                                              3
279 DATA CARD           1
280 DATA CARD    RICHWO22    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
281 DATA CARD    11983  3    31 1473                                                              3
282 DATA CARD           1
283 DATA CARD    RICHWO31    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
284 DATA CARD    11983  3    31 1473                                                              3
285 DATA CARD           1
286 DATA CARD    RICHWO32    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
287 DATA CARD    11983  3    31 1473                                                              3
288 DATA CARD           1
289 DATA CARD    RICHWO51    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
290 DATA CARD    11983  3    31 1473                                                              3
291 DATA CARD           1
292 DATA CARD    RICHWO52    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
293 DATA CARD    11983  3    31 1473                                                              3
294 DATA CARD           1
295 DATA CARD    RICHWO61    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
296 DATA CARD    11983  3    31 1473                                                              3
297 DATA CARD           1
298 DATA CARD    RICHWO62    6         31   2  1 1983       .245  1.0 6.031  457              6.8026PE
299 DATA CARD    11983  3    31 1473                                                              3
300 DATA CARD           1
301 DATA CARD    FALLSPH1    6         15   2 54 1983       .187  1.0 6.500  203              7.0726PE
302 DATA CARD    11983  3    15 1364                                                              3
303 DATA CARD           1
304 DATA CARD    FALLSPH2    6         15   2 54 1983       .187  1.0 6.500  203              7.0726PE
305 DATA CARD    11983  3    15 1364                                                              3
306 DATA CARD           1
307 DATA CARD    FALLSPH3    6         15   2 54 1982       .187  1.0 6.500  203              7.0726PE
308 DATA CARD    11983  3    15 1364                                                              3
309 DATA CARD           1
310 DATA CARD    SOUTHPN3    6         13   2 54 1982       .285  1.0 6.413  182              7.8726PE
311 DATA CARD    11983  3    13 1398                                                              3

1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
          1         2         3         4         5         6         7         8
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1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
          1         2         3         4         5         6         7         8

312 DATA CARD          1
313 DATA CARD    SOUTHPW4    6        13   2 54 1983       .285  1.0 6.413  182      7.8726PE
314 DATA CARD    11983   3    13 1398                                                 3
315 DATA CARD          1
316 DATA CARD    SOUTHPW5    6        13   2 54 1982       .285  1.0 6.413  182      7.8726PE
317 DATA CARD    11983   3    13 1398                                                 3
318 DATA CARD          1
319 DATA CARD    SOUTHPW6    6        13   2 54 1983       .285  1.0 6.413  182      7.8726PE
320 DATA CARD    11983   3    13 1398                                                 3
321 DATA CARD          1
322 DATA CARD    CHESTPH7    6        13   2 54 1982       .195  1.0 6.437  182      7.8726PE
323 DATA CARD    11983   3    13 1398                                                 3
324 DATA CARD          1
325 DATA CARD    CHESTPW8    6        13   2 54 1983       .195  1.0 6.437  182      7.8726PE
326 DATA CARD    11983   3    13 1398                                                 3
327 DATA CARD          1
328 DATA CARD    CHESTPW9    6        13   2 54 1982       .195  1.0 6.437  182      7.8726PE
329 DATA CARD    11983   3    13 1398                                                 3
330 DATA CARD          1
331 DATA CARD    BARBSPW5    6        16   2 54 1983       .261  1.0 6.479  218      7.0726PE
332 DATA CARD    11983   3    16 1364                                                 3
333 DATA CARD          1
334 DATA CARD    PLYMWOD9    6        28   2 54 1982       .245  1.0 6.449  413      7.3326PE
335 DATA CARD    11983   3    28 1474                                                 3
336 DATA CARD          1
337 DATA CARD    PLYMWO15    6        28   2 54 1983       .245  1.0 6.449  413      7.3326PE
338 DATA CARD    11983   3    28 1474                                                 3
339 DATA CARD          1
340 DATA CARD    CROMBYD     6         3   2  1 1983        .99 .26 6.346   31      39.0626PE
341 DATA CARD     1983   3     3 1045                                                 3
342 DATA CARD    DELAWRED    6         3   2  1 1983        .99 .26 6.413   31      39.0626PE
343 DATA CARD     1983   3     3 1045                                                 3
344 DATA CARD    SCHYKILD    6         3   2  1 1983        .99 .26 6.413   31      39.0626PE
345 DATA CARD     1983   3     3 1045                                                 3
346 DATA CARD    RICHMDD     6         3   2  1 1983        .99 .26 6.031   31      39.0626PE
347 DATA CARD     1983   3     3 1045                                                 3
348 DATA CARD    SOUTHNKD    6         3   2  1 1983        .99 .26 6.413   31      39.0626PE
349 DATA CARD     1983   3     3 1045                                                 3
350 DATA CARD    COHOX       3       350   2                  1.                      28PE
351 DATA CARD      121700  758800 2431920                     5
352 DATA CARD    COHOY       3        60   2                  1.                      28PE
353 DATA CARD      1 7860 1410080                             4
354 DATA CARD    COHOZ       3        30   2                  1.                      28PE
355 DATA CARD      1 5040                                     1
356 DATA CARD    COHOW       3        60   2                  1.                      28PE
357 DATA CARD      1 6048 15 7776 37 9760                     5
358 DATA CARD    UNIT #47    1        67   8                1.000.97102.011  487     0.33  CI
359 DATA CARD     1983   2    40 1107    46 1140    55 1146    62 1208    67 1340    2
360 DATA CARD    DUMMY10     1        67   9                1.000.97102.011  487     0.33  PEJ
361 DATA CARD PE1.00
362 DATA CARD     1983   2    40 1107    46 1140    55 1146    62 1208    67 1340    2
363 DATA CARD    MDYRII&2    4       220   2 49 1982        .145  1.                      28CBJ

1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
          1         2         3         4         5         6         7         8
```

O&M

	CT COSTS
1985	2
1986	3
1987	4
1988	3
1989	4
1990	5
1991	4
1992	5
1993	5
1994	5
1995	5
1996	
1997	
1998	
1999	
2000	
2001	
2002	
2003	
2004	
2005	

CT O&M costs escalate from 1996 to 2011 at a constant six percent rate.

ANNUAL COST OF RETURNING 458 MW OF CT'S UNTIL 2012

Year	Cost Million $	Year	Cost Million $
1986	1	2001	43
1987	1	2002	40
1988	2	2003	38
1989	1	2004	35
1990	1	2005	32
1991	2	2006	30
1992	1	2007	27
1993	1	2008	24
1994	2	2009	22
1995	1	2010	19
		2011	17
1996	2		
1997	56		
1998	52		
1999	49		
2000	46		

The annual cost from 1986 to 1996 assumes continuing the CT lease payments until normal termination on 10/1/1996.

Paid-in balance 12/31/84	$25,903,000
Plus: Additional payments to $10,027,000 x 9/12	7,520,000
Balance at 10/1/85	$33,423,000
Annual credit 10/1/85 to 10/1/96 $33,423,000 /11	$ 3,038,000
Annual lease rental payment (see IR-OCA-5-2)	4,387,000
Annual cost to ratepayers	$ 1,349,000

The annual cost from 1997 to 2012 assumes purchase of the CT's from the lessor at the fair market value upon normal termination of the lease on 10/1/1996. Fair market value is assumed to be $200 million or 10% of the cost of new CT's in 1996. Capital cost for a 15 year life extension of the CT's is assumed to be $0.

DOCKET NO. R-850152

12/16/85 1469

I-840381
OCA Exhibit No. 6

Q. IR-OCA-5-6. In response to OCA Interrogatory 1-49 in R-842590 the Company stated that until the Spring of 1984, PECo attempted to negotiate "a long term lease" of its share of Salem 2. Please specify the longest length of the lease which the Company attempted to negotiate.

A. IR-OCA-5-6. The term of the proposed lease was one of several variables involved in the negotiations. The latest termination date offered by PECo, subject to concessions by the lessee on other facets of the lease arrangements, was May 31, 1996.

I-840381
OCA Exhibit No. 7

IR-OCA-1-49

Q. IR-OCA-1-49. Please explain why PECO will no longer sell its share of Salem Unit #2 output to Jersey Central Power & Light.

A. IR-OCA-1-49. The FERC Order issued June 17, 1981 accepted the PE-JC Agreement for filing to continue in effect through December 31, 1984. PECO instituted negotiations with GPU in the fall of 1982 for a long term lease of its share of Salem 2. Negotiations continued until the spring of 1984, but despite diligent efforts the Company was unable to reach a reasonable agreement. The agreement therefore was not extended.

IR-OCA-1-50

Q. IR-OCA-1-50. Has PECO attempted to sell some or all of its share at Salem Unit #2 to any other utilities? If not, why not? If yes, please provide copies of correspondence and documents soliciting such sales?

A. IR-OCA-1-50. The Company has investigated the possibility of selling its share of Salem 2 to other utilities. This investigation revealed that there were no other prospective buyers within reasonable transmission distance from PECO. No formal written solitations were made.

DOCKET NO. R-850152

12/16/85 14bg
DC

Q.IR-OCA-6-19 For each generating unit owned either wholly or in part by PECO, please provide:

(a) The capacity of PECO's share of the unit;
(b) The monthly generation in KWH which was produced by PECO's share of each unit for the period January 1982 to the present;
(c) The monthly cost of fuel consumed by PECO's share of each unit for the period January 1982 to the present;
(d) The monthly capacity factor that each unit operated at for the period January 1982 to present.

A.IR-OCA-6-19 The Attachment IR-OCA-6-19 contains six sheets of data. This data represents the statistics requested by this interrogatory question as recorded in the Company records.

a) The capacity is listed by unit or station to conform with the monthly output records of the Company.

b) The monthly net MWH of the specific units or stations is shown in the attached schedule.

c) Since PECO records for fossil plants only record a total fuel cost by station, the values of Fuel expenses for Eddystone and Cromby are for the entire station but tabulated opposite the first unit of that station as it appears on the attached schedule.

d) The Quarterly Capacity Factors for the various units has been reported in response to IR-OCA-6-22. However, if monthly values are imperative, they can be calculated by dividing the net MWH in the month by the product of the period hours for the month times the capacity shown for unit or station.

Responsible Witness: J. J. Carroll, Staff Engineer, Services Division

PREPARED
CHECKED
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COMPARED AND FOOTED

Attachment
IR-OCA-6-19
Sheet 1 of 6

		19 82 MWH	19 82 Fuel $/1,000	19 83 MWH	19 83 Fuel $/1,000	19 84 MWH	19 84 Fuel $/1,000	19 85 MWH	19 85 Fuel $/1,000
Schuylkill 166 MW									
January	1	55 490	2 993	(349)	15	12 930	5 158	62 299	3 140
February	2	39 440	2 181	(395)	18	45 832	2 575	62 001	3 323
March	3	31 309	1 892	(368)	14	31 258	1 252	39 471	2 165
April	4	12 166	726	(607)	16	(355)	7	(305)	56
May	5	(544)	7	14 372	737	(394)	9	11 198	653
June	6	(404)	5	38 602	1 988	(361)	20	11 726	643
July	7	64 764	3 416	75 307	3 724	(460)	11	34 733	1 588
August	8	27 661	1 484	31 959	1 477	7 124	452	12 557	625
September	9	(532)	8	69 699	3 605	31 843	1 713	12 015	658
October	10	(388)	84	50 332	2 622	36 615	2 831		
November	11	349	110	(479)	27	32 950	1 679		
December	12	(343)	18	59 045	2 197	30 744	1 668		
Keystone No. 1 311 MW									
Jan	16	88 185	15 374	(2 100)	8 035	(2 361)	16 951	132 123	10 958
Feb	17	91 918	10 923	(4 288)	20 512	31 119	7 389	128 666	11 290
Mar	18	119 328	9 392	15 043	12 058	68 748	7 676	159 710	5 582
Apr	19	146 234	7 936	(2 507)	11 297	104 936	7 152	53 876	2 700
May	20	95 006	5 283	(2 418)	8 356	113 847	10 378	122 997	9 732
June	21	106 955	7 031	(1 560)	6 232	126 095	18 345	104 392	5 595
July	22	95 517	11 578	(1 636)	12 086	74 941	11 070	(2 800)	8 212
Aug	23	132 399	11 471	(2 653)	17 296	147 720	12 411	101 392	9 553
Sept	24	70 940	2 586	(2 432)	11 276	143 703	12 925	122 992	9 658
Oct	25	50 709	7 860	(1 239)	9 963	116 144	11 096		
Nov	26	(1 406)	7 522	(1 308)	8 626	67 925	12 309		
Dec	27	(1 591)	2 591	(1 601)	13 991	122 195	12 583		
Keystone No. 2 - 936 MW									
Jan	31	174 056		165 330		(2 569)		115 545	
Feb	32	32 587		161 552		36 130		110 966	
Mar	33	(1 105)		161 223		107 670		(958)	
Apr	34	(1 038)		180 383		126 320		(676)	
May	35	17 282		165 767		(2 764)		(778)	
June	36	112 006		173 985		142 484		9 895	
July	37	131 526		152 452		129 388		114 763	
Aug	38	52 208		157 056		53 690		145 312	
Sept	39	108 272		80 303		148 371		134 524	
Oct	40	116 419		(464)		167 800			
Nov	41	123 969		(417)		162 563			
Dec	42	158 052		(752)		169 792			
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IR-OCA-6-19
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		19 82 MWH	19 82 Fuel $/1000	19 83 MWH	19 83 Fuel $/1000	19 84 MWH	19 84 Fuel $/1000	19 85 MWH	19 85 Fuel $/1000
Eddystone No. 3 200 MW									
Jan	2	73 947		28 718		137 237		69 609	
Feb	3	54 343		54 369		19 851		83 766	
Mar	4	54 852		67 659		(2 113)		18 982	
Apr	5	33 435		68 864		(2 164)		64 815	
May	6	8 247		60 675		35 619		50 704	
June	7	10 416		(857)		107 601		6 994	
July	8	73 984		109 894		88 432		51 890	
Aug	9	45 490		128 017		102 403		31 435	
Sept	10	5 225		79 958		48 228		42 215	
Oct	11	10 195		69 101		88 640			
Nov	12	14 157		71 050		130 632			
Dec	13	22 748		122 046		56 083			
	14								
	15								
Eddystone No. 4 ~~200~~ 400 MW									
Jan	17	76 929		29 030		143 808		(696)	
Feb	18	61 446		55 647		39 245		(887)	
Mar	19	32 837		63 683		24 918		(1 272)	
Apr	20	40 487		54 623		24 259		10 661	
May	21	22 396		21 519		23 252		46 656	
June	22	5 508		40 512		105 773		19 093	
July	23	16 092		117 005		98 337		42 845	
Aug	24	47 791		124 829		112 704		38 623	
Sept	25	14 437		80 323		50 199		27 957	
Oct	26	36 117		82 601		72 464			
Nov	27	44 452		77 677		69 291			
Dec	28	30 436		62 756		18 031			
	29								
Cromby No. 1 Jan	30	6 812	5 570	78 812	4 638	86 176	5 800	75 214	6 030
144 MW Feb	31	85 806	5 219	(979)	3 810	60 562	4 151	62 539	5 549
Mar	32	74 357	5 567	67 202	6 621	58 498	4 590	39 215	2 705
Apr	33	76 628	4 320	82 947	5 704	43 611	3 203	75 553	3 172
May	34	68 572	1 387	62 802	4 427	28 013	1 741	59 322	3 585
June	35	67 259	2 655	79 467	4 407	90 115	4 449	60 094	3 158
July	36	80 006	1 886	95 216	6 845	12 202	5 256	72 947	3 385
Aug	37	44 744	3 482	88 435	6 797	83 219	5 300	75 774	3 514
Sept	38	41 105	1 480	81 373	5 564	24 764	3 284	47 095	1 028
Oct	39	42 224	1 232	87 411	5 969	24 845	3 329		
Nov	40	75 969	4 552	82 547	4 224	(1 092)	4 351		
Dec	41	80 649	3 934	87 956	5 103	3 567	2 137		
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Form [illegible] Rev 0 2/70

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Attachment
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	1982 MWH	1982 Fuel $1000	1983 MWH	1983 Fuel $1000	1984 MWH	1984 Fuel $1000	1985 MWH	1985 Fuel $1000
Crosby No. 2								
201MW Jan	107 359		67 295		72 169		84 821	
Feb	79 902		83 520		50 819		24 074	
Mar	76 707		118 198		48 944		32 644	
Apr	53 996		90 340		40 037		30 632	
May	(542)		71 781		(466)		48 076	
June	24 556		57 677		47 313		38 702	
July	3 685		105 235		78 647		33 346	
Aug	43 606		101 512		66 172		21 317	
Sept	7 270		72 214		38 590		(704)	
Oct	21 819		83 217		55 273			
Nov	55 038		63 379		86 964			
Dec	43 206		67 696		35 113			
Delaware								
250MW Jan	81 440	4 538	22 904	1 456	85 689	4 503	47 561	2 572
Feb	58 660	3 491	25 420	1 493	61 903	3 670	66 213	3 519
March	32 527	2 352	27 753	1 592	58 281	2 275	36 831	2 182
Apr	31 492	1 922	19 072	1 102	36 295	2 054	40 755	2 235
May	20 510	1 410	38 541	2 095	59 804	3 182	40 194	2 014
June	17 944	1 250	40 328	2 345	59 104	3 170	15 019	801
July	54 416	3 155	95 099	6 954	28 112	4 105	34 855	1 688
Aug	23 076	1 406	65 980	1 421	86 366	4 101	40 278	1 782
Sept	4 099	468	44 734	2 543	41 639	2 246	26 760	1 418
Oct	13 605	1 052	37 466	2 123	68 286	3 510		
Nov	27 197	1 827	33 956	2 009	103 364	5 214		
Dec	18 530	1 241	85 910	4 448	21 578	1 515		
Richland								
166MW Jan	26 158	1 690	6 122	576	37 244	2 356	14 855	1 052
Feb	(533)	152	8 287	698	10 876	849	14 474	1 020
Mar	(596)	158	19 792	1 358	2 878	392	22 899	1 455
Apr	5 258	494	17 919	1 153	(973)	71	21 219	1 290
May	(569)	82	12 344	908	5 200	462	0	36
June	826	180	14 060	950	39 584	2 188	(1 376)	44
July	29 494	1 859	28 384	1 822	17 268	1 858	(692)	33
Aug	(1 107)	72	33 [illegible]	2 073	34 987	2 148	(671)	14
Sept	191	184	[illegible] 767	2 045	6 753	536	(555)	17
Oct	(1 670)	87	14 298	975	6 986	567		
Nov	(2 913)	165	16 170	1 110	38 273	2 411		
Dec	3 228	431	36 257	1 673	11 800	842		

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	19 MWH	82 Fuel $1000	19 MWH	83 Fuel $1000	19 MWH	84 Fuel $1000	19 MWH	85 Fuel $1000
Southwack								
336MW								
Jan	19 596	2 151	1 333	334	36 236	2 870	10 326	962
Feb	1 271	126	993	277	7 855	761	2 555	356
Mar	(1 354)	159	11 284	864	(1 309)	122	(1 435)	88
Apr	4 687	456	5 263	506	(1 482)	67	(1 210)	69
May	(1 451)	57	5 442	554	(1 671)	131	4 235	456
June	(1 222)	46	14 679	1 099	26 760	1 924	(3 325)	89
July	20 587	1 618	31 839	2 265	16 174	1 285	1 698	255
Aug	4 120	444	30 031	2 176	32 443	2 445	7 680	629
Sept	(351)	137	23 335	1 721	347	116	5 421	532
Oct	(1 311)	90	686	229	1 948	262		
Nov	1 334	349	6 006	707	21 599	1 584		
Dec	(108)	202	15 357	1 265	(1 389)	104		
Keystone								
957MW								
Jan	204 042	3 537	128 797	1 640	199 577	2 376	238 553	2 882
Feb	168 176	2 017	132 569	1 737	215 407	2 608	176 318	2 171
Mar	203 744	2 536	204 635	2 544	222 681	2 642	207 171	2 556
Apr	213 178	2 952	142 391	1 855	179 984	2 126	194 250	2 403
May	152 546	1 842	87 716	1 068	93 430	1 187	215 766	2 800
June	132 694	1 705	138 944	1 744	238 658	2 853	159 060	2 024
July	145 304	1 949	212 935	2 667	234 459	3 000	154 083	2 187
Aug	207 509	2 529	225 935	2 817	177 219	2 173	163 913	2 591
Sept	153 150	2 480	216 066	2 554	79 425	996	237 934	3 055
Oct	223 724	2 662	182 227	2 285	121 209	1 440		
Nov	172 402	2 208	154 916	2 132	116 370	1 507		
Dec	153 552	2 500	200 633	2 496	144 751	1 770		
Conemaugh								
952MW								
Jan	155 223	2 982	205 961	3 109	142 643	1 820	218 766	3 553
Feb	80 028	1 364	131 988	1 971	124 023	1 618	144 158	2 289
Mar	160 463	2 767	133 691	1 948	210 600	2 831	113 781	1 558
Apr	81 628	1 419	227 065	3 234	221 208	3 039	198 201	3 201
May	83 610	1 402	188 183	2 982	232 367	3 146	214 935	3 260
June	152 875	2 641	196 698	2 911	217 954	3 128	158 258	3 200
July	148 498	2 555	175 264	2 530	207 871	3 100	218 342	3 232
Aug	148 514	2 557	208 171	2 595	193 264	2 649	193 423	3 039
Sept	130 371	2 322	217 751	2 735	154 109	2 121	108 024	1 637
Oct	93 928	1 664	142 647	1 933	195 444	2 867		
Nov	94 655	1 760	147 093	1 801	103 214	1 661		
Dec	122 787	2 902	181 293	1 993	229 175	4 174		

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IR-OCA-6-19
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	19 Q2 MWH	Q2 Fuel $/1000	19 Q3 MWH	Q3 Fuel $/1000	19 Q4 MWH	Q4 Fuel $/1000	19 Q5 MWH	Q5 Fuel $/1000
Diesels								
13.6 MW Jan	171	4	87	4	151	4	89	6
Feb	287	5	196	4	111	4	83	2
Mar	100	3	124	4	135	5	139	2
Apr	119	4	76	4	111	3	143	2
May	130	4	117	4	210	6	81	2
June	159	4	212	4	102	7	82	2
July	166	5	116	4	79	3	255	3
Aug	91	3	94	4	109	5	314	4
Sept	161	4	111	5	118	4	54	2
Oct	156	6	145	4	90	3		
Nov	213	4	149	3	221	7		
Dec	154	4	143	5	138	5		
Croydon								
325 MW Jan	10 021	826	18 694	1 430	62 477	4 143	27 527	1 763
Feb	2 728	240	10 713	878	12 469	916	20 375	1 463
Mar	3 342	291	23 445	1 714	5 309	381	6 408	453
Apr	10 881	701	28 205	2 074	3 468	279	9 696	723
May	940	92	16 061	1 164	9 726	739	3 359	226
June	2 127	236	13 701	1 121	34 938	2 809	3 863	307
July	22 385	1 717	27 446	2 131	19 239	1 448	6 619	512
Aug	3 370	300	32 389	2 587	28 499	2 268	11 694	878
Sept	8 099	639	30 812	2 484	11 854	938	7 152	550
Oct	5 382	13	8 649	606	10 151	719		
Nov	5 239	928	20 708	1 423	53 582	3 774		
Dec	4 062	356	46 551	3 332	12 715	929		
Simple Cycle CTs								
937 MW Jan	24 406	2 502	5 222	462	41 560	3 508	8 104	732
Feb	9 822	1 061	4 612	439	5 932	556	2 583	264
Mar	6 648	633	9 083	795	4 335	391	2 462	226
Apr	10 160	991	10 388	868	2 327	255	2 017	180
May	1 668	185	9 289	763	4 038	381	3 069	291
June	2 256	216	12 279	1 095	64 109	6 072	5 536	316
July	13 300	1 313	22 210	2 003	8 996	820	3 866	355
Aug	2 637	289	28 921	2 564	17 942	1 627	13 109	1 027
Sept	10 922	959	38 749	3 542	4 833	427	4 764	408
Oct	7 352	755	7 277	608	2 652	276		
Nov	3 558	408	25 519	2 188	1 962	192		
Dec	4 938	481	33 542	2 477	2 285			

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		A2 MWH	A2 Fuel $/1000	A3 MWH	A3 Fuel $/1000	A4 MWH	A4 Fuel $/1000	A5 MWH	A5 Fuel $/1000
Peach Bottom #2									
1122 MW	Jan	256 785	3 093	316 007	1 361	245 451	1 425	(1 616)	187
	Feb	155 197	(1 193)	297 147	1 414	198 110	1 007	(2 054)	167
	Mar	(1 976)	637	314 871	1 194	310 701	1 484	(3 583)	179
	Apr	(1 723)	626	319 176	1 508	251 566	1 239	(4 164)	158
	May	(2 440)	622	148 919	850	(2 840)	700	(4 273)	394
	June	(3 324)	658	315 482	1 423	(2 961)	729	(5 402)	467
	July	271 958	2 059	37 517	362	(2 426)	213	82 440	1 190
	Aug	240 611	3 643	(2 785)	218	(2 729)	202	164 402	1 697
	Sept	283 667	3 626	(3 372)	220	(1 619)	179	159 840	1 839
	Oct	278 227	(1 439)	(3 495)	228	(2 011)	200		
	Nov	342 332	2 034	(2 194)	221	(1 553)	186		
	Dec	237 086	1 258	255 387	1 350	(1 690)	178		
Peach Bottom #3									
1287 MW	Jan	330 687	898	258 172	1 388	182 082	1 658	281 022	2 006
	Feb	265 438	3 457	103 342	641	284 921	2 141	3 478	312
	Mar	319 661	2 291	(3 159)	209	333 961	2 920	278 825	1 932
	Apr	321 363	1 833	(1 557)	187	324 913	2 379	274 698	1 939
	May	292 428	2 142	(2 303)	129	324 247	2 382	262 449	1 893
	June	326 192	2 260	(3 708)	424	92 047	964	218 682	1 600
	July	318 187	2 259	(3 056)	514	254 688	2 151	91 870	808
	Aug	318 365	958	(2 785)	512	295 818	2 203	(3 942)	61
	Sept	309 456	481	(3 876)	507	314 952	2 227	(4 842)	172
	Oct	322 545	5 505	114 831	1 254	311 740	2 241		
	Nov	301 691	1 999	262 197	2 020	154 474	1 301		
	Dec	295 267	2 006	309 625	2 323	254 498	1 831		
Salem #1									
1137 MW	Jan	2 234	350	(3 355)	133	252 950	1 622	333 170	2 833
	Feb	(1 138)	336	(5 589)	132	263 249	1 558	311 622	2 618
	Mar	(2 145)	513	(2 494)	308	(2 801)	198	176 820	2 520
	Apr	53 167	879	(2 981)	303	(1 099)	201	135 209	2 802
	May	303 195	1 801	84 710	197	(1 401)	213	147 217	2 868
	June	304 234	1 876	332 249	2 077	(1 258)	198	122 753	2 742
	July	307 520	1 847	337 891	2 144	(1 552)	192	140 003	2 810
	Aug	300 782	1 723	251 142	1 685	(2 428)	602	139 539	2 804
	Sept	305 522	1 717	306 182	1 916	(4 685)	238	140 372	2 638
	Oct	159 999	1 127	347 041	2 096	32 735	564		
	Nov	(1 198)	922	318 545	1 908	118 923	1 398		
	Dec	(1 120)	979	317 897	1 922	253 419	2 339		
Salem #2									
1111 MW	Jan	301 093	2 057	99 987	665	(2 164)	1 721	(1 008)	185
	Feb	298 923	1 982	(1 188)	55	(6 013)	254	(8 841)	350
	Mar	339 892	2 216	(2 715)	61	275 347	1 999	(5 140)	453
	Apr	287 871	1 982	(1 676)	62	49 979	501	35 653	769
	May	336 079	1 858	(2 934)	61	264 341	1 826	250 639	1 923
	June	330 008	2 088	(1 896)	62	181 765	1 014	302 597	2 236
	July	336 709	1 681	(3 203)	311	50 947	530	100 863	1 635
	Aug	264 842	1 757	101 625	748	245 830	1 723	285 670	2 158
	Sept	306 546	1 945	58 911	543	272 952	1 901	315 856	2 294
	Oct	260 593	1 655	70 998	566	35 869	399		
	Nov	246 549	1 580	(1 859)	463	(1 199)	206		
	Dec	239 983	1 639	(1 226)	(560)	(1 114)	688		

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I-840381
OCA Exhibit No. 8

Q. IR-Staff-1-7. Provide the capacity factor for combustion turbines by unit or by station including those currently designated for retirement in R-842590. State how the capacity factor was determined.

A. IR-Staff-1-7. The capacity factors for combustion turbines are provided as Attachment IR-Staff-1-7. The capacity factors were calculated by dividing the monthly generation by the MW capacity and the number of hours in that month, in the following fashion:

$$\frac{\text{Monthly Generation}}{\text{MW Capacity} \times \text{Hours in Month}} \times 100$$

The MW capacity that was used was the summer net rating from May through September and the winter net rating from October through April.

COMBUSTION TURBINE
CAPACITY FACTOR - %

	SCHUYLKILL	EDDYSTONE	CHESTER	DELAWARE	RICHMOND
August 1983	2.2	3.1	1.4	2.4	5.4
September 1983	2.6	5.9	3.2	6.3	6.6
October 1983	0.19	0.23	0.17	0.28	0.99
November 1983	4.0	2.5	1.0	2.7	2.7
December 1983	2.3	2.6	1.6	2.8	4.6
January 1984	5.8	3.8	0.98	3.9	6.1
February 1984	0.31	0.62	0.19	0.38	0.86
March 1984	0.23	0.42	0.47	0.32	0.57
April 1984	0.29	0.24	0	0.29	0.26
May 1984	0.62	0.39	0.38	0.44	0.76
June 1984	6.6	8.5	8.7	6.2	10.4
July 1984	3.5	1.3	0.60	1.6	0.89

	SOUTHWARK	PLYMOUTH	FALLS	MOSER	CROYDON
August 1983	2.1	0.40	0.73	3.1	15.5
September 1983	4.5	1.0	2.8	5.6	13.2
October 1983	0.81	0.02	0.08	0.31	2.7
November 1983	2.4	0.09	0.87	10.3	6.6
December 1983	2.7	0.05	1.1	3.5	14.3
January 1984	1.2	0	0.80	0.29	19.2
February 1984	0.28	0	0.14	0.26	4.1
March 1984	0.23	0	0.30	0.59	1.6
April 1984	0.22	0	0.25	0.76	1.1
May 1984	0.53	0	0.26	0.34	4.0
June 1984	9.7	0	15.7	10.5	14.9
July 1984	0.83	0	3.4	3.0	8.0

DOCKET NO. R-850152

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DOCUMENT FOLDER

Q. IR-OCA-9-10. Please provide the overall PJM reserve and the PECo reserve requirement as determined by PJM for the years 1970-1985.

A. IR-OCA-9-10. Reserve requirements are expressed as percent of PJM and PECo forecast summer peak demands.

	PJM	PECo*
1970	19.0	19.0
1971	22.0	22.0
1972	22.0	22.0
1973	22.0	22.0
1974	20.0	14.7
1975	20.0	14.8
1976	20.0	15.3
1977	20.0	12.8
1978	20.0	14.0
1979	20.0	17.6
1980	22.0	21.4
1981	22.0	24.6
1982	22.0	22.7
1983	22.0	22.5
1984	22.0	20.8
1985	22.0	21.3

*Data for years 1974-1980 applies to PE Group. (Includes PECo, Atlantic City Electric and Delmarva Power and Light). Prior to 1974, PJM companies used the PJM reserve requirement as a planning guide, and individual company reserve requirements were not determined separately and were not contractually binding.

Responsible Witness: C.H.Rush, Chief Engineer, Research & Planning Division

DOCKET NO. R-850152

12/16/85 ltr hdg
JK

Q. IR-OCA-15-2. Please state the amount of PECo's installed capacity (summer rating) for the years 1979 through 1984. (Please state for each year whether or not Salem 2 is included.)

A. IR-OCA-15-2. PECo's installed capacity (summer rating) as of year-end was:

Year	Capacity in MW	Salem 2 Included
1979	7727	No
1980	7698	No
1981	8006*	Yes
1982	8006*	Yes
1983	7974*	Yes
1984	7765*	Yes

*Does not include the effect of various capacity sales to GPU within these years.

Responsible Witness: C.H. Rush, Chief Engineer - Research & Planning Division

DOCKET NO. R-850152

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DEC 19 1985

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DOCKET NO. I-80100341

TESTIMONY

OF

LEWIS J. PERL

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

ON BEHALF OF

PHILADELPHIA ELECTRIC COMPANY

MARCH 5, 1981

nera

Consequently, even if the cost of economy interchange were zero, the cost of electricity from the Limerick facility would still be cheaper than that from the least-cost alternative. As indicated in Table 4A, even ignoring economy interchange cost, the most likely savings from completing Limerick would be $3.3 billion and the probabilistic expected savings would be $2.9 billion. While the magnitude of the savings from constructing Limerick depends upon the oil price, reductions in the oil price, regardless of how large, cannot alter the fundamental conclusion that there will be savings to consumers from completing the Limerick facility. Of course, if oil or coal prices rise more rapidly than is assumed in this analysis, the base savings from Limerick would increase substantially.

This result also suggests the relative insensitivity of the savings from completing Limerick to variations in demand growth between 1979 and 1990. The slower the overall demand growth over the period, the lower the price of economy interchange power which represents the short-run alternative to Limerick. As demand growth falls, the cost of economy interchange falls because this energy is supplied from more successively economic units. Regardless of demand growth over the period, however, economy interchange costs cannot fall to zero. Since the lifetime savings from Limerick would be positive even if this occurred, the decision to complete Limerick is insensitive to the rate of growth in the short run.

Q. What would be the effect on your estimate of shifts in the construction schedule for the Limerick facility?

A. Obviously, the savings from constructing Limerick are also sensitive to the construction schedule for these facilities. The savings from Limerick will decrease significantly if completion of this facility is

further delayed; this delay will increase the cost of Limerick and decrease the savings in economy interchange cost that occurs if the facility is completed in time. In order to test the sensitivity of my conclusions to this result, I examined the savings from constructing Limerick if this facility is delayed so that the first unit is completed in 1987 and the second unit in 1989. The results of this analysis are examined in Table 4A. The present value of the savings from constructing Limerick is $4.1 billion if the schedule is delayed to 1987 versus $5.2 billion if it is completed on time. As we can see from this table, even with a delay of this magnitude, there are still significant savings from completing the Limerick facility. They are reduced substantially, however, by comparison with those occurring in the base case. In this regard, it should be pointed out that the schedule for completing Limerick is very sensitive to the availability of financing. If funds to complete the facility are constrained as a result of inadequate rates of return or an inadequate quality of earnings, the schedule for the facility is likely to be delayed. Such schedule delays substantially reduce the economic advantages of constructing Limerick.

Q. What are the other key factors to which your results are sensitive?

A. Each of the cost components is subject to some uncertainties and the sensitivity of the savings from completing Limerick to these uncertainties is summarized in Table 4B. There is substantial uncertainty regarding the capital costs of these facilities. There are two primary components to this uncertainty. First, my estimates are based upon an extrapolation of the cost experience of nuclear plants built in the past. While my statistical analysis of the historic data accounts for nearly 90 percent of plant-to-plant cost variation, forecasts from this data base are

DOCKET NO. I-80100341

TESTIMONY

OF

LEWIS J. PERL

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

ON BEHALF OF

PHILADELPHIA ELECTRIC COMPANY

REVISED
APRIL 9, 1981

nera

energy from a base load, mine mouth, coal-fired alternative. Even if economy interchange were assigned such a price, however, the cost of electricity from the Limerick facility would still be cheaper than that from the least-cost alternative. As indicated in Table 4A, even pricing economy interchange at the cost of energy from base load coal plants, the most likely savings from completing Limerick would be $4.4 billion and the probabilistic expected savings would be $3.8 billion. Thus, while the magnitude of the savings from constructing Limerick depends both upon the oil price and demand growth, reductions in the oil price or the growth rate, regardless of how large, cannot alter the fundamental conclusion that there will be savings to consumers from completing the Limerick facility. Of course, if oil or coal prices rise more rapidly or if growth is faster than is assumed in this analysis, the base savings from Limerick would increase substantially.

Q. What would be the effect on your estimate of shifts in the construction schedule for the Limerick facility?

A. Obviously, the savings from constructing Limerick are also sensitive to the construction schedule for these facilities. The savings from Limerick will decrease significantly if completion of this facility is

further delayed; this delay will increase the cost of Limerick and decrease the savings in economy interchange cost that occurs if the facility is completed in time. In order to test the sensitivity of my conclusions to this result, I examined the savings from constructing Limerick if this facility is delayed so that the first unit is completed in 1987 and the second unit in 1989. The results of this analysis are examined in Table 4A. The present value of the savings from constructing Limerick is $4.4 billion if the schedule is delayed to 1987 versus $5.7 billion if it is completed on time. As we can see from this table, even with a delay of this magnitude, there are still significant savings from completing the Limerick facility. They are reduced substantially, however, by comparison with those occurring in the base case. In this regard, it should be pointed out that the schedule for completing Limerick is very sensitive to the availability of financing. If funds to complete the facility are constrained as a result of inadequate rates of return or an inadequate quality of earnings, the schedule for the facility is likely to be delayed. Such schedule delays substantially reduce the economic advantages of constructing Limerick.

Q. What are the other key factors to which your results are sensitive?

A. Each of the cost components is subject to some uncertainties and the sensitivity of the savings from completing Limerick to these uncertainties is summarized in Table 4B. There is substantial uncertainty regarding the capital costs of these facilities. There are two primary components to this uncertainty. First, my estimates are based upon an extrapolation of the cost experience of nuclear plants built in the past. While my statistical analysis of the historic data accounts for nearly 90 percent of plant-to-plant cost variation, forecasts from this data base are

OCA EXHIBIT NO. 10

DOCKET NO. R-850152

Hbg 12/16/85 ✓

PECO STATEMENT NO. _____

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKET NUMBER R-811626

PHILADELPHIA ELECTRIC COMPANY

GENERAL INCREASE IN ELECTRIC RATES

REBUTTAL TESTIMONY

of

DR. LEWIS J. PERL

REVISED

December 22, 1981

n/e/r/a'

rebuttal testimony in this proceeding, Mr. Benderly presented evidence that the coverage improvement resulting from the inclusion of $1.0 billion of CWIP in rate base would reduce bond yield by 25 basis points and reduce required equity returns by 52 basis points. PE has calculated the savings in annual revenue requirements from these reductions in the cost of money. These have been used in Table 2 to modify the revenue requirements with CWIP in rate base. With this modified revenue stream, we find that the inclusion of CWIP in rate base generates a break-even discount rate of ~~14.2~~ 13.7 percent.

In addition, it appears to me that without the inclusion of CWIP in rate base PE could find it quite difficult to maintain the construction schedule for Limerick. Without CWIP, maintenance of the construction schedule requires PE to raise $1.6 billion from external sources over the period 1983 to 1985. Raising this large sum could pose serious financial difficulties given PE's current price/book ratio and bond rating. If the sum cannot be raised, the only alternative is to spend less and allow some slippage in the construction schedule. However, given the amount already invested in the project and the current stage of construction, such slippage would be very expensive to consumers. To calculate the costs of slippage, I compared the effect on PE's revenue requirements of on-time completion with a six-month slippage in the construction schedule for both units. The estimated effect on revenue requirements, which takes account of both higher completion costs and increased energy costs during the period of delay, has a present value of ~~$264~~ 274 million (at a discount rate of ~~14.2~~ 13.7 percent). The year-by-year cost of the delay was used to modify revenue requirements in the AFDC case. The result is described in Table 2. If the

inclusion of CWIP in rate base were to avert such a delay, the return on the temporary rate increase associated with CWIP would be increased to 17.2 percent. Combining this effect with the effect of the lower rates described above results in a return on CWIP of 15.7 percent. Thus, a complete analysis of the break-even discount rate on $1.0 billion of CWIP in rate base would suggest that the allowance of such CWIP is justified as long as the opportunity cost of capital to consumers is less than 15.7 percent.

December 29, 1981

ERRATA SHEET

Rebuttal Testimony of
Lewis J. Perl
On Behalf of Philadelphia Electric Company

Docket No. R-811626

(Revised Testimony Submitted December 22, 1981)

The Following Changes Reflect New Information
Provided By The Philadelphia Electric Company:

Reference	Filed As	Should Be
Page 3, Line 22	14.2	13.7
Line 24	19.0	18.7
Page 6, Line 8	14.2	13.7
Line 24	$254	$274
	14.2	13.7
Page 7, Line 4	19.0	18.7
Line 7	19.0	18.7
Line 23	19.0	18.7
Page 11, Line 2	14.2	13.7
	19.0	18.7
Page 13, Line 19	19.0	18.7
Table 1, Line 1, Col. (2)	14.2	13.7
Line 2, Col. (2)	19.0	18.7 (see attached)
Table 2, Col (2)		REPLACED (see attached)

DOCKET NO. R-850152

12/16/85 HBg
JJC

IR-OCA-16-9

Please confirm that the predicted cost for Limerick from the regression equation in Exhibit 1, page 3 yields a predicted cost of 2675 or an excess cost of 7.2 percent.

Answer

The regression equation in Exhibit 1, page 3 yields a predicted cost of $2,717/kW for Limerick 1. This predicted cost is calculated by (1) multiplying the regression parameters to the appropriate Limerick 1 characteristics; (2) summing the cross products; and (3) taking the antilog of the summed log of Limerick 1's predicted cost. The ratio of actual costs to this predicted costs is 1.056. Refer to the accompanying table for the derivation of Limerick 1's predicted nuclear capital cost.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

ATTACHMENT IR-OCA-16-9

DERIVATION OF LIMERICK 1 NUCLEAR CAPITAL COST

Variable	Limerick Characteristic	Regression Coefficient	Cross Product
	(1)	(2)	(1)*(2) (3)
Constant	1	7.7808	7.7808
Subsequent Unit Indicator	0	-0.4183	0.0000
Rock Foundation Indicator	1	-0.1245	-0.1245
Single Unit BWR Indicator	0	0.2289	0.0000
Log of Wage Index—Journeymen	-0.0496	0.3807	-0.0189
Northeast Indicator	1	0.2119	0.2119
Utility is Constructor Indicator	0	-0.2490	0.0000
Complex Cooling System Indicator	1	0.0579	0.0579

Log of Limerick 1 Predicted Nuclear Capital Cost: 7.907

Limerick 1 Predicted Nuclear Capital Cost (1984 $/Kw): $2.717

OCA EXHIBIT NO. 77

DOCKET NO. R-850152

12/16/85 Hbg TC

IR-OCA-16-2

Concerning the response to IR-OCA-2-8, please provide the results of the regression shown in Exhibit 1, p.3, without the Cooling Tower Indicator variable. If such a run has not been done, please do so. In answering this question, please provide the results of all statistical tests performed, including a listing of the predicted values and/or residuals from the regression for each unit in the sample, both with and without the Cooling Tower variable. Please calculate the excess cost percentage for Limerick from this run (i.e. Limerick's actual cost/predicted cost).

Answer

The ratio of the predicted cost to the actual cost based on the regression equation without the cooling tower indicator variable for Limerick is 1.08. The ratio to the average of the standardized costs is 1.065. The results of the regression equation, including a listing of the predicted values and residuals is shown in Attachment IR-OCA-16-2.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

NUCLEAR CAPITAL COSTS FOR POST-1971 PLANTS
STANDARDIZED TO LIMERICK 1
(With no Complex Cooling System Variable)

Plant	Standardized Direct Cost
Hatch 2	1733
Arkansas Nuclear One 2	1852
McGuire	1929
St. Lucie 2	1977
Susquehanna	2093
Summer	2199
Farley	2200
LaSalle	2204
Hope Creek	2263
Clinton 1	2620
Perry	2445
San Onofre	2451
WPPSS 2	2474
Marble Hill	2487
Wolf Creek	2524
Braidwood	2533
Callaway	2573
Palo Verde	2606
Shoreham	2708
Fermi 2	2724
Millstone 3	2762
Commanche	2793
Nine Mile Point 2	2817
Limerick 1	2868
Waterford 3	2893
Byron	2959
Beaver Valley 2	2966
Watts Bar	3001
Seabrook	3032
Catawba	3040
Riverbend	3053
Midland	3066
Grand Gulf	3128
South Texas	3180
Bellafonte	3241
Harris	3453
Vogtle	3561
Average, Excluding Limerick 1	2694

DEP VARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
MODEL	6	7.039946	1.173324	30.766	0.0001
ERROR	52	1.983155	0.038138		
C TOTAL	58	9.023101			

ROOT MSE	0.195289	R-SQUARE	0.7802
DEP MEAN	7.536017	ADJ R-SQ	0.7549
C.V.	2.591402		

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > |T|	STANDARDIZED ESTIMATE	VARIABLE LABEL
INTERCEP	1	7.800564	0.053729	145.184	0.0001	0.000000	INTERCEPT
SUBSQ	1	-0.410622	0.054479	-7.537	0.0001	-0.515796	SUBSEQUENT UNIT INDICATOR
CMPROCK	1	-0.109825	0.061507	-1.786	0.0800	-0.135803	COMPOSITE ROCK FOUND. INDICATOR
SINGBWR	1	0.247238	0.088396	2.797	0.0072	0.204438	SINGLE UNIT B&F INDICATOR
NWAIND	1	0.346795	0.165131	2.100	0.0406	0.153446	LOG OF MEANS WAGE INDEX
NEI	1	0.210767	0.072039	2.926	0.0051	0.209901	NORTHEAST INDICATOR
UTILCMX	1	-0.257859	0.065353	-3.946	0.0002	-0.280510	UTILCOM VAR ONLY FOR TVA,DUKE,COMM UNITS

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
1	SANONO2	7.806	7.874	-.067961
2	SANONO3	7.371	7.463	-.091961
3	MILLSTN3	7.906	7.867	0.039451
4	FERMI2	8.015	7.990	0.025547
5	SHORHAM	8.319	8.300	0.019517
6	NINEMPT2	8.184	8.125	0.059141
7	WATTSBR	7.412	7.352	0.059925
8	WATTSBR	7.122	6.941	0.181047
9	WPPSS2	8.016	8.087	-.070660
10	FARLEY1	7.227	7.584	-.356932
11	FARLEY2	7.130	7.173	-.043335
12	PALOV1	7.651	7.817	-.166231
13	PALOV2	7.453	7.407	0.046190
14	PALOV3	7.455	7.407	0.048556
15	HARRIS1	7.960	7.554	0.406612
16	HARRIS2	7.238	7.143	0.094768
17	PERRY1	7.659	7.716	-.057001
18	PERRY2	7.197	7.305	-.108511
19	BRAIDWD	7.398	7.453	-.054678
20	BRAIDWD	7.002	7.042	-.039435
21	BYRON1	7.554	7.428	0.125341
22	BYRON2	7.109	7.018	0.090998
23	LASALL1	7.400	7.562	-.162165
24	LASALL2	6.941	7.152	-.211180
25	MIDLAND1	7.963	7.852	0.110912
26	MIDLAND2	7.618	7.442	0.175885

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
27	MARBHIL	7.676	7.674	0.001884
28	MARBHIL	7.126	7.264	-.138043
29	CATAWBA	7.438	7.294	0.144058
30	CATAWBA	7.010	6.884	0.126695
31	MCGUIRE1	6.841	7.294	-.453380
32	MCGUIR2	6.682	6.884	-.201276
33	BEAVRVL2	8.119	8.008	0.110458
34	STLUCIE2	7.465	7.760	-.294980
35	HATCH2	6.858	7.285	-.426858
36	CLINTON1	8.030	8.043	-.013427
37	WOLFCRK	7.597	7.648	-.050609
38	GRAGULF1	7.650	7.638	0.011845
39	GRAGULF2	7.523	7.227	0.295653
40	SUSQUE1	7.645	7.856	-.210994
41	SUSQU2	7.180	7.446	-.265585
42	LIMERIK	7.961	7.884	0.077084
43	LIMERIK	7.542	7.474	0.068010
44	SEABRK1	7.981	7.902	0.078424
45	SEABRK2	7.676	7.492	0.184135
46	HOPECRK	8.076	8.235	-.159661
47	SUMMER	7.351	7.539	-.188368
48	COMANCH	7.743	7.622	0.120874
49	COMANCH	7.186	7.212	-.025385
50	BELLAF1	7.480	7.351	0.128946
51	BELLAF2	7.205	6.940	0.265089
52	CALLAWY	7.632	7.663	-.031644
53	SOTEX1	8.089	7.780	0.309385
54	SOTEX2	7.401	7.369	0.032048
55	VOGTLE1	7.974	7.690	0.283836
56	VOGTLE2	7.582	7.279	0.302826
57	RIVRBND	8.138	7.999	0.139543
58	ARKONE2	6.827	7.187	-.360375
59	WATERFD3	7.834	7.748	0.085880

OF RESIDUALS 8.42437E-13
OF SQUARED RESIDUALS 1.983155

OCA EXHIBIT NO. 48

DOCKET NO. R-850152

Mog 12/16/85 JK

IR-OCA-16-5

Please provide the results of the regression in Exhibit 1, p. 3, for the sample excluding Limerick 1 from the database. If such a run has not been done, please do so. Please recalculate the "standardized average" for all units excluding Limerick. Also, please provide the results of all statistical tests performed, including a listing of the predicted values and/or residuals from the regression for each unit in the sample, both with and without the Cooling Tower variable. Please calculate the excess cost percentage for Limerick under this run (i.e. Limerick's actual cost/predicted cost).

Answer

The ratio of actual to predicted costs excluding Limerick is 1.063. Excluding the cooling tower variable and omitting Limerick 1 the ratio of actual to predicted is 1.091. The ratio of the actual costs to the average of standardized costs excluding Limerick 1 is 1.047 and also excluding cooling tower variables is 1.075.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

NUCLEAR CAPITAL COSTS FOR POST-1971 PLANTS
STANDARDIZED TO LIMERICK 1
(Without Limerick 1)

Plant	Standardized Direct Cost
Hatch 2	1725
Arkansas Nuclear One 2	1869
McGuire	2045
St. Lucie 2	2057
Susquehanna	2104
Farley	2219
Hope Creek	2264
LaSalle	2267
Summer	2347
Perry	2435
WPPSS 2	2453
San Onofre	2532
Palo Verde	2561
Callaway	2566
Marble Hill	2629
Braidwood	2646
Wolf Creek	2668
Fermi 2	2739
Clinton 1	2758
Shoreham	2848
Nine Mile Point 2	2861
Limerick 1	2868
Beaver Valley 2	2917
Millstone 3	2927
Byron	2928
Commanche	2966
Watts Bar	2991
Midland	3001
Waterford 3	3014
Catawba	3045
Riverbend	3051
Grand Gulf	3138
Seabrook	3212
Bellafonte	3230
South Texas	3312
Harris	3488
Vogtle	3536
Average, Excluding Limerick 1	2740

EP VARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

OURCE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
ODEL	7	6.899853	0.985693	25.415	0.0001
IROR	50	1.939203	0.038784		
TOTAL	57	8.839056			

ROOT MSE	0.196937	R-SQUARE	0.7806
DEP MEAN	7.528683	ADJ R-SQ	0.7499
C.V.	2.615819		

ARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > !T!	STANDARDIZED ESTIMATE	VARIABLE LABEL
NTERCEP	1	7.780692	0.057521	135.268	0.0001	0.000000	INTERCEPT
UBSQ	1	-0.416571	0.056001	-7.439	0.0001	-0.525554	SUBSEQUENT UNIT INDICATOR
ARROCK	1	-0.125033	0.063676	-1.964	0.0551	-0.155407	COMPOSITE ROCK FOUND. INDICATOR
INGPWR	1	0.232303	0.092229	2.519	0.0150	0.193853	SINGLE UNIT BWR INDICATOR
NWAIND	1	0.378062	0.170304	2.220	0.0310	0.168869	LOG OF MEANS WAGE INDEX
EI	1	0.207458	0.075178	2.760	0.0081	0.200740	NORTHEAST INDICATOR
TILCMX	1	-0.248891	0.066462	-3.745	0.0005	-0.272824	UTILCON VAR ONLY FOR TVA,DUKE,COMP UNITS
XCOOLS	1	0.056236	0.057417	0.979	0.3321	0.070468	COMPLEX COOLING SYSTEM INDICATOR

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
1	SANONO2	7.806	7.860	-.054675
2	SANONO3	7.371	7.444	-.072727
3	MILLSTN3	7.906	7.825	0.080975
4	FERMI2	8.015	8.001	0.014652
5	SHORHAM	8.319	8.265	0.053924
6	NINEMPT2	8.184	8.126	0.058376
7	WATTSBR	7.412	7.375	0.037110
8	WATTSBR	7.122	6.958	0.164101
9	WPPSS2	8.016	8.112	-.095550
10	FARLEY1	7.227	7.595	-.368435
11	FARLEY2	7.130	7.179	-.048887
12	PALOV1	7.651	7.855	-.204105
13	PALOV2	7.453	7.439	0.014260
14	PALOV3	7.455	7.439	0.015626
15	HARRIS1	7.960	7.563	0.397807
16	HARRIS2	7.238	7.146	0.091911
17	PERRY1	7.659	7.739	-.080420
18	PERRY2	7.197	7.323	-.125980
19	BRAIDWD	7.398	7.428	-.030335
20	BRAIDWD	7.002	7.012	-.009146
21	BYRON1	7.554	7.498	0.055626
22	BYRON2	7.109	7.041	0.067237
23	LASALL1	7.400	7.553	-.153033
24	LASALL2	6.941	7.137	-.196100
25	MIDLAND1	7.963	7.837	0.126108

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
26	MIDLAND2	7.618	7.421	0.197030
27	MARBHIL	7.676	7.694	-.017802
28	MARBHIL	7.126	7.278	-.151780
29	CATAWBA	7.438	7.312	0.126429
30	CATAWBA	7.010	6.895	0.115018
31	MCGUIRE1	6.841	7.256	-.414773
32	MCGUIR2	6.682	6.839	-.156721
33	BEAVRVL2	8.119	8.041	0.077735
34	STLUCIE2	7.465	7.737	-.271493
35	HATCH2	6.858	7.306	-.447836
36	CLINTON1	8.030	8.008	0.021750
37	WOLFCRK	7.597	7.609	-.011651
38	GRAGULF1	7.650	7.654	-.004542
39	GRAGULF2	7.523	7.238	0.285254
40	SUSQUE1	7.645	7.870	-.224765
41	SUSQU2	7.180	7.454	-.273407
42	LIMERIK	7.542	7.484	0.057663
43	SEABRK1	7.981	7.864	0.116758
44	SEABRK2	7.676	7.447	0.228414
45	HOPECRK	8.076	8.251	-.175676
46	SUMMER	7.351	7.490	-.139615
47	COMANCH	7.743	7.581	0.162105
48	COMANCH	7.186	7.165	0.021794
49	BELLAF1	7.480	7.374	0.106205
50	BELLAF2	7.205	6.957	0.248306
51	CALLAWY	7.632	7.682	-.050317
52	SOTEX1	8.089	7.758	0.331115
53	SOTEX2	7.401	7.342	0.059728
54	VOGTLE1	7.974	7.716	0.257466
55	VOGTLE2	7.582	7.300	0.282408
56	RIVRBND	8.138	8.016	0.122523
57	ARKONE2	6.827	7.194	-.367230
58	WATERFD3	7.834	7.723	0.110520

OF RESIDUALS	8.35332E-13
OF SQUARED RESIDUALS	1.939203

NUCLEAR CAPITAL COSTS FOR POST-1971 PLANTS
STANDARDIZED TO LIMERICK 1
(Without Limerick 1 and Complex Cooling System variable)

Plant	Standardized Direct Cost
Hatch 2	1711
Arkansas Nuclear One 2	1831
McGuire	1908
St. Lucie 2	1958
Susquehanna	2090
Farley	2178
LaSalle	2179
Summer	2180
Hope Creek	2248
Perry	2424
San Onofre	2427
WPPSS 2	2440
Marble Hill	2464
Wolf Creek	2504
Braidwood	2509
Callaway	2552
Palo Verde	2577
Clinton 1	2582
Fermi 2	2691
Shoreham	2691
Millstone 3	2762
Commanche	2766
Nine Mile Point 2	2803
Waterford 3	2865
Limerick 1	2868
Byron	2930
Beaver Valley 2	2961
Watts Bar	2969
Catawba	3007
Riverbend	3008
Seabrook	3028
Midland	3035
Grand Gulf	3098
South Texas	3146
Bellafonte	3207
Harris	3419
Vogtle	3519
Average, Excluding Limerick 1	2669

VARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

CE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
	6	6.862648	1.143775	29.514	0.0001
	51	1.976408	0.038753		
AL	57	8.839056			

OOT MSE	0.196858	R-SQUARE	0.7764
EP MEAN	7.528683	ADJ R-SQ	0.7501
.V.	2.614774		

BLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > |T|	STANDARDIZED ESTIMATE	VARIABLE LABEL
CEP	1	7.799410	0.054231	143.818	0.0001	0.000000	INTERCEPT
	1	-0.407963	0.055285	-7.379	0.0001	-0.514694	SUBSEQUENT UNIT INDICATOR
OCK	1	-0.111469	0.062126	-1.794	0.0787	-0.138548	COMPOSITE ROCK FOUND. INDICATOR
WR	1	0.252258	0.089915	2.806	0.0071	0.210504	SINGLE UNIT B&W INDICATOR
ND	1	0.343819	0.166611	2.064	0.0442	0.153574	LOG OF MEANS WAGE INDEX
	1	0.202933	0.075006	2.706	0.0092	0.196361	NORTHEAST INDICATOR
HX	1	-0.257122	0.065902	-3.902	0.0003	-0.281847	UTILCON VAR ONLY FOR TVA,DUKE,CONM UNITS

	ID	ACTUAL	PREDICT VALUE	RESIDUAL
	SANONO2	7.806	7.872	-.066180
	SANONO3	7.371	7.464	-.092840
	MILLSTN3	7.906	7.856	0.049784
	FERMI2	8.015	7.992	0.023771
	SHORHAM	8.319	8.295	0.023835
	NINEMPT2	8.184	8.120	0.064545
	WATTSBR	7.412	7.350	0.061291
	WATTSBR	7.122	6.942	0.179754
	WPPSS2	8.016	8.090	-.074152
	FARLEY1	7.227	7.582	-.355052
	FARLEY2	7.130	7.174	-.044118
	PALOV1	7.651	7.816	-.164933
	PALOV2	7.453	7.408	0.044828
	PALOV3	7.455	7.408	0.047194
	HARRIS1	7.960	7.552	0.408235
	HARRIS2	7.238	7.144	0.093732
	PERRY1	7.659	7.713	-.053988
	PERRY2	7.197	7.305	-.108156
	BRAIDWD	7.398	7.450	-.052448
	BRAIDWD	7.002	7.042	-.039864
	BYRON1	7.554	7.426	0.127364
	BYRON2	7.109	7.018	0.090961
	LASALL1	7.400	7.562	-.161579
	LASALL2	6.941	7.154	-.213258
	MIDLAND1	7.963	7.851	0.112510
	MIDLAND2	7.618	7.443	0.174824

ID	ACTUAL	PREDICT VALUE	RESIDUAL
MARBHIL	7.676	7.672	0.004542
MARBHIL	7.126	7.264	-.138042
CATAWBA	7.438	7.293	0.144970
CATAWBA	7.010	6.885	0.124913
MCGUIRE1	6.841	7.293	-.452507
MCGUIR2	6.682	6.885	-.203062
BEAVRVL2	8.119	7.999	0.119459
STLUCIE2	7.465	7.760	-.294170
HATCH2	6.858	7.288	-.429262
CLINTON1	8.030	8.047	-.017331
WOLFCRK	7.597	7.645	-.048180
GRAGULF1	7.650	7.636	0.014185
GRAGULF2	7.523	7.228	0.295378
SUSQUE1	7.645	7.846	-.200745
SUSQU2	7.180	7.438	-.257995
LIMERIK	7.542	7.466	0.075836
SEABRK1	7.981	7.892	0.089062
SEABRK2	7.676	7.484	0.192113
HOPECRK	8.076	8.231	-.155892
SUMMER	7.351	7.538	-.186871
COMANCH	7.743	7.620	0.123087
COMANCH	7.186	7.212	-.025836
BELLAF1	7.480	7.350	0.130305
BELLAF2	7.205	6.942	0.263798
CALLAWY	7.632	7.661	-.029082
SOTEX1	8.089	7.779	0.310366
SOTEX2	7.401	7.371	0.030367
VOGTLE1	7.974	7.690	0.284035
VOGTLE2	7.582	7.282	0.300371
RIVRBND	8.138	8.003	0.135258
ARKONE2	6.827	7.188	-.361035
WATERFD3	7.834	7.747	0.086580

OF RESIDUALS 8.24230E-13
OF SQUARED RESIDUALS 1.976408

OCA EXHIBIT NO. 7C

DOCKET NO. R-850152

12/16/85 Hbg

JK

IR-OCA-16-1

With regard to the 4% excess you calculate for Limerick 1 vis a vis the "standardized" average cost for comparison units, please

a. confirm that the actual cost for Limerick 1 and Common in 1984 dollars assumes escalation in 1985 and 1986 of 6%;

b. indicate the revised "actual" cost per kW in 1984 dollars, and the associated excess cost, using (1) the actual Handy-Whitman index for the North-Atlantic region in 1985, and (2) the 4.5% inflation rate PECO assumes for 1986 in its life-cycle cost analysis of Limerick 1.

Answer to 1a

Actual cost data for Limerick 1 and common assumes 6 percent escalation for 1985 and 1986. The cost data and assumed escalation were provided to NERA by PECO.

Answer to 1b

If the Handy Whitman index for 1985 is changed to the actual value and the escalation for 1986 is 4.5 percent, the cost per kilowatt in 1984 dollars is $2,872 rather than $2,868.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

Attachment IR-DCA-16-1

DIRECT EXPENDITURES ON THE LIMERICK PLANT, BY YEAR

Based on Most Recent (9/85) PECO Estimate
Using H-W Index 7/1985 and assumed 4.5 % escalation in 1986

	Unit 1 Directs	Common	Handy Whitman Nuclear Construction Index	Unit 1 Directs	Common
	(millions of nominal dollars)			(millions of mid-1984 dollars)	
1969			75		
1970			81		
1971	21.8	9.4	88	58.2	25.1
1972	23.2	10.7	95	57.4	26.5
1973	43.8	12.2	100	102.9	28.7
1974	50.3	21.0	114	103.7	43.3
1975	57.1	23.6	127	105.7	43.7
1976	75.6	29.1	136	130.6	50.3
1977	78.8	34.8	146	126.8	56.0
1978	53.9	30.8	155	89.3	46.7
1979	81.1	23.8	170	112.1	32.9
1980	124.6	36.6	184	159.1	46.7
1981	133.1	96.6	200	156.4	101.8
1982	196.5	125.8	217	212.8	136.2
1983	264.2	134.9	227	273.5	139.7
1984	250.0	157.3	235	250.0	157.3
1985	82.0	67.3	242	79.6	65.4
1986	3.2	8.3	253	3.0	8.6
Total for all years:	1544.2	813.2		2021.2	1008.8
Total for 1985 on:	85.2	76.6		82.6	74.0
Total Cost/kw, Unit 1 & Common				2872	

IR-STAFF-LIM-07

Refer to PECO Statement No. 11, Page 2 of Schedule 2. What criteria was used for selecting the units listed on page 2 of Schedule 2? List all criteria and the basis for using it.

Answer

The criteria used in selection were:

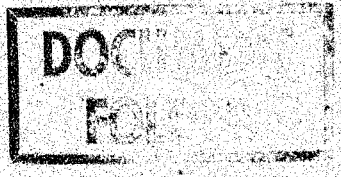
1. Construction permit date issued in 1972 or later;
2. Single unit or first unit of multiunit plant; and
3. Availability of data.

The basis for criterion one is that (1) empirically over the entire database there was a marked increase in nuclear capital costs for units with a construction permit date in 1972 or later vis-a-vis units with a construction permit date prior to 1972; (2) regressions run splitting the database at this date indicate much different coefficients; and (3) a study by EPRI argues that regulatory climate changed markedly since 1972.

The basis of criterion two is that the standardization was calculated for Limerick 1, thus units with similar characteristics (either first of a multiunit plant or single units) are the appropriate sample with which to compare construction times.

Criterion three is so stated.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.



R-850152

GEC Exhibit # 3

12/16/85
Hbg TJK

Q. IR-OCA-2-25. With regard to the life-cycle comparisons of revenue requirements from Limerick 1 described on pp. 56-57, please provide the following information:

a. a complete listing of "PECo's standard corporate assumptions" that were used in the analysis;
b. detailed workpapers displaying all calculations involved in the analysis, including annual costs and benefits of Limerick 1 and the non-Limerick 1 alternative used for comparison, and also including all senstivitity tests. If any or all of these calculations were performed with an electronic spreadsheet such as Lotus 1-2-3, please provide a copy of all worksheet files containing input, accounting conventions, formulas, intermediate and final results, and documentation associated with the analysis.
c. an exhaustive listing of all assumptions, and their sources, used to make the comparisons, including:
   (1) high and low values of cost and availability of purchased power from west of PJM broken out into as much detail as possible, i.e., first-year energy and capacity charges by source, annual escalation rates, etc.;
   (2) the yearly load growth (both peak demand and annual energy) assumed for PECo and other utilities or divisions of PJM;
   (3) all assumptions pertaining to Limerick 1 (and allocable common), including costs for O&M, capital additions, fuel (by fuel cycle component, both per quantity and per million Btu), heat rate, decommissioning cost, etc., including the assumptions and methodologies underlying each variable;
   (4) details of the estimated cost associated with imposition of acid rain controls, including the affected generating units and the types and costs of the abatement measures assumed in the analysis;
   (5) specific data concerning the cancellation of ECAR generating units under construction, including names, annual capacity factors and output ratings of the units in question;
   (6) alternative load forecasts used for each ECAR utility or group of utilities in the analysis, along with a copy of the relevant forecast document(s) themselves;

(7) detailed input assumptions for production-cost runs underlying calculations of PJM energy charges for the entire period of analysis, including initial fuel costs and escalation rates for each generating station that figures in the calculations.

d. workpapers supporting the calculation of revenue requirements under the assumptions of 50 and 100 percent increases in PJM capacity charges.

A. IR-OCA-2-25. a. PECo's current assumptions, as indicated in the responses to IR-OCA-2-25b and c were relied on.

b. The requested data is provided in Attachment IR-OCA-2-25b.

Item 1 (3 pages) provides the development of the yearly net benefits for the life cycle analysis of Limerick 1 and 50% of common facilities based on two times the current capacity deficiency charge and either a 50% reduction or elimination of 2 party purchases. These analyses were used as the basis for determining the range of benefits achieved by Limerick 1 over its life cycle. Adjustments to reflect existing capacity deficiency charges and a 1.5 times increase in charges are shown on page 3 of 3.

Item 2 (2 pages) details the other operation and maintenance expenses used in the life cycle analysis.

Item 3 (5 pages) provides the revenue requirements associated with the original cost of Limerick 1 and 50% of common facilities together with subsequent capital additions used in the life cycle analysis.

Item 4 (19 pages) develops the operation and maintenance expense differential and the capital differential associated with NO_x and SO_2 emissions that were used in the life cycle analysis.

Item 5 (2 pages) contains the development of the cost of money that was used in the life cycle analysis.

Item 6 (1 page) contains data relating to the development of book cost, AFDC, tax depreciation basis, ITC base, and realty tax base associated with Limerick 1 & 50% of common facilities used in the life cycle analysis.

Item 7 (6 pages) contains the year by year carrying charges associated with Limerick 1 & 50% of common facilities, exclusive of capital additions, used in the life cycle analysis.

Item 8 (121 pages) contains the year by year carrying charges associated with post commercial capital additions used in the life cycle analysis.

Item 9 (4 pages) contains the bases for the capacity charges used in the life cycle analysis.

In addition, a copy of the production cost runs is supplied to the OCA for the cases of 50% and 100% reduction in two-party purchases that were used in the life cycle analysis.

c. In addition to the assumptions stated in part a, the following general assumptions were used in the Limerick life cycle analysis:

Capital Related Assumptions

-Commercial operation date of Unit #1 is February 15, 1986
-Acid rain effects start in 1993
-Reduction or elimination of two party purchases start in 1994
-For post commercial capital additions, the following AFUDC rates were used:

1986	9.6%
1987	9.7%
On & after 1988	9.8%

Inflation

1986	4.5%
1987	5.0%
1988 & beyond	6.0%

(1) The requested values may be determined from the input and output of the production cost runs.
(2) The requested values may be determined from the input and output of the production cost runs.
(3) The requested values for the fuel costs and heat rate may be determined from the input and output of the production cost runs.

Capital Additions Assumptions for Limerick life cycle analysis

The yearly direct cost additions for the years 1987 to 1994 were determined by escalating $10,000,000 (1984$) by 6.8%/year. Direct cost additions for the years 1995 through 2023 were escalated by 6%/year. The direct cost addition for 1986 was determined by escalating $3,500,000 (1984$) by 6.8%/year. The AFDC rates for these additions are listed in the part c of the general assumptions portion of this interrogatory.

O&M Assumptions for Limerick life cycle analysis

For yearly Limerick station O&M excluding fuel and other O&M the Company utilized as its base a December 1985 cost level and escalated this level using a 3% real growth rate from 1986-1990 and a 0% real growth rate from 1991 through 2024.

For Limerick other O&M, the following assumptions were used in the life cycle analysis:

Decommissioning - The Company utilized the March 1984 nuclear related cost of Limerick 1 & 50% of common facilities (Company Exhibit NBM-1) escalated this cost to a December 1985 level (approximately $120 million) and amortized it over a 38 year period, which reflects the period that rates from this proceeding would be in effect until the retirement date of Limerick 1. The resulting annual expense amounts to $3.16 million. These dollars are expected to be invested in Pennsylvania tax free bonds and deposited in an escrow account. The Company estimates that the revenues to be received from customers will be exempt from federal and state taxes in accordance with the Tax Reform Act of 1984.

The Company intends to use the prompt removal method of decommissioning as described in Company Exhibit NBM-1. Decomissioning is expected to commence at the end of operating life.

Insurance

Property coverage - The Company utilized a $5 million base for 1986 that was derived from the recent Limerick 2 show cause proceedings and escalated this figure using the inflation rates from IR-OCA-2-25a.

Liability - The Company utilized a $.7 million base for 1986 that was derived from the recent Limerick 2 show cause proceeding and escalated this figure using the inflation rates from IR-OCA-2-25a.

Replacement Power - The Company utilized a $1.5 million base for 1986 that was derived from the recent Limerick 2 show cause proceedings. No escalation was applied to this figure.

NO_x and SO_2 Capital and Expense Assumptions

The assumptions are provided in IR-OCA-2-25c(4)

(4) Acid Rain Adjustments

Sulfur Dioxide (SO_2)
The impact of the imposition of acid rain controls on the economics of Limerick No. 1 was calculated as follows:

National Economic Research Associated (NERA) ran their linear optimization model of PJM to determine how utilities in PJM would comply with legislation requiring a ten million ton reduction in SO_2 emissions. This analysis used the capital and operating cost estimates shown in Attachment IR-OCA-2-25b, Item 4 (pages 3-6).

The change in fuel costs for each unit and the change in operating costs due to the installation of scrubbers were incorporated into PECo's production cost runs. The costs used for each plant are shown in Attachment IR-OCA-2-25b, Item 4 (pages 7-10).

The capital and operating costs associated with installation of scrubbers on the Conemaugh plant were calculated using a cost of $225/kW and 5.3 mills/kWh, respectively for PECo's share of the investment. The data shown in Attachment IR-OCA-2-25b, Item 4 (pages 11-13) derives the incremental investment and increased operating cost due to acid rain.

Nitrogen Oxide (NO_x)

The impact of the imposition of acid rain controls requiring no increases in NO_x emissions over 1980 levels was calculated as follows:

1980 emission levels by plant were calculated using fuel consumption data from the National Coal Association and standard emission rates for coal, oil and gas combustion.

Emissions for 1993, 2000, 2011 and 2024 were calculated by multiplying the emission rates referred to above by the fuel consumption data from the production cost runs.

The cost of NO_x controls was calculated using a total cost of $222 per ton. This data is shown in Attachment IR-OCA-2-25b, Item 4 (pages 14-19).

(5) There is no specific data concerning the cancellation of ECAR generating units under construction. The Statement on page 56 of PECo Statement No. 15 referred to units in ECAR on which construction is not currently proceeding and noted that cancellation of these units would reduce the capacity available for export to PJM below the level used in the study "ECAR/MAAC Interregional Power Transfer Analysis. A Presentation to the U.S. Department of Energy" dated June 1985.

(6) See IR-OCA-2-25c(5).

(7) The requested values may be determined from the input and output of the production cost runs.

d. Please see Attachment IR-OCA-2-25b, Item 9 and Attachment IR-OCA-2-25b, Item 1, page 3 of 3 for the requested information.

Responsible Witnesses: W. Hieronymus, Director-Putnam, Hayes & Bartlett Inc.

T. P. Hill, Jr., Asst. Manager-Rate Division

LITERATURE UNIT NO. 1 & 3UP COMBUSTION
FUEL SAVINGS/W LOAD SHED AND ACID RAIN
ANNUAL REVENUE REQUIREMENTS
MILLIONS$

100% inclusive in capacity charges 9/23/85

#1691, 3 pages

50% rodin 2 party pur 2x rate

BREAKEVEN NPV AT 2008 16.83581720

YEAR		ORIG COST &ADDITIONS CARRYING CHARGES(a) (1)	STATION O&M (2)	OTHER O&M(b) (3)	TOTAL O & M AND CAPITAL COSTS (4)=(1)+(2)+(3)	DIFFERENTIAL FOR SO2 AND NOX (5)	FUEL SAVINGS(c) (6)	CAPACITY CHARGES AVOIDED (7)	TOTAL BENEFITS (8)=(5)+(6)+(7)	BENEFITS LESS COSTS (9)=(8)-(4)
1	1986	$747.27	$79.01	$31.24	$857.52	$0.00	$150.82	$80.57	$231.39	($626.13)
2	1987	$713.90	$85.33	$31.62	$830.85	$0.00	$186.04	$88.78	$274.82	($556.03)
3	1988	$685.60	$93.01	$32.98	$811.59	$0.00	$209.45	$97.23	$306.68	($504.91)
4	1989	$660.09	$101.39	$39.96	$801.44	$0.00	$322.36	$144.03	$466.39	($335.05)
5	1990	$635.23	$110.51	$33.90	$779.64	$0.00	$282.46	$152.68	$435.14	($344.50)
6	1991	$610.30	$117.14	$37.10	$764.54	$0.00	$320.80	$161.84	$482.64	($281.90)
7	1992	$585.46	$124.17	$41.19	$750.82	$0.00	$480.03	$171.54	$651.57	($99.25)
8	1993	$560.69	$131.62	$43.70	$736.01	$2.77	$423.14	$181.84	$607.75	($128.26)
9	1994	$536.03	$139.52	$40.96	$716.51	$2.83	$550.85	$192.75	$756.43	$39.92
10	1995	$511.44	$147.89	$57.53	$716.86	$2.91	$843.13	$204.31	$1,050.35	$333.49
11	1996	$504.40	$156.76	$48.41	$709.57	$3.07	$734.74	$216.57	$954.38	$244.81
12	1997	$495.18	$166.17	$51.62	$712.97	$3.04	$799.49	$229.57	$1,032.10	$319.13
13	1998	$486.13	$176.14	$65.36	$727.63	$3.12	$1,072.74	$243.35	$1,319.21	$591.58
14	1999	$477.26	$186.70	$54.99	$718.95	$3.36	$834.45	$257.95	$1,095.76	$376.81
15	2000	$468.59	$197.91	$61.72	$728.22	$3.07	$979.39	$273.43	$1,255.89	$527.67
16	2001	$460.10	$209.78	$75.58	$745.46	$3.18	$1,256.13	$289.85	$1,549.16	$803.70
17	2002	$451.84	$222.37	$65.12	$739.33	$3.44	$1,175.93	$307.24	$1,486.61	$747.28
18	2003	$443.83	$235.71	$69.60	$749.14	$3.76	$1,158.32	$325.68	$1,487.76	$738.62
19	2004	$436.03	$249.85	$88.42	$774.30	$4.31	$1,684.26	$345.22	$2,033.79	$1,259.49
20	2005	$428.51	$264.84	$76.04	$769.39	$4.64	$1,377.00	$365.94	$1,747.58	$978.19
21	2006	$421.25	$280.73	$81.50	$783.48	$4.88	$1,501.83	$387.90	$1,894.61	$1,111.13
22	2007	$414.35	$297.58	$101.84	$813.77	$5.16	$2,085.02	$411.18	$2,501.36	$1,687.59
23	2008	$407.75	$315.43	$88.98	$812.16	$5.61	$1,826.78	$435.84	$2,268.23	$1,456.07
24	2009	$401.54	$334.35	$94.61	$830.51	$5.94	$1,823.03	$461.98	$2,290.95	$1,460.44
25	2010	$395.74	$354.42	$120.16	$870.32	$6.27	$2,684.52	$489.71	$3,180.50	$2,310.18
26	2011	$390.37	$375.69	$103.97	$870.03	$6.64	$2,226.64	$519.10	$2,752.38	$1,882.35
27	2012	$385.52	$398.23	$111.33	$895.08	$6.88	$2,386.35	$550.25	$2,943.48	$2,048.40
28	2013	$381.21	$422.12	$140.89	$944.22	$7.12	$3,393.46	$583.27	$3,983.85	$3,039.63
29	2014	$377.54	$447.45	$121.90	$946.89	$7.56	$2,946.52	$618.27	$3,572.35	$2,625.46
30	2015	$374.64	$474.30	$130.85	$979.79	$7.84	$3,011.42	$655.37	$3,674.63	$2,694.84
31	2016	$367.56	$502.75	$166.29	$1,036.60	$8.12	$4,511.25	$694.70	$5,214.07	$4,177.47
32	2017	$363.16	$532.92	$143.46	$1,039.54	$8.63	$3,726.32	$736.37	$4,471.32	$3,431.78
33	2018	$361.90	$564.89	$154.33	$1,081.12	$8.94	$3,797.64	$780.55	$4,587.13	$3,506.01
34	2019	$364.73	$598.79	$195.17	$1,158.69	$9.28	$5,489.06	$827.39	$6,325.73	$5,167.04
35	2020	$373.05	$634.71	$170.44	$1,178.20	$9.92	$4,658.72	$877.04	$5,545.68	$4,367.48
36	2021	$390.15	$672.80	$182.35	$1,245.30	$10.25	$4,949.91	$929.67	$5,889.83	$4,644.53
37	2022	$421.66	$713.17	$231.63	$1,366.46	$10.63	$7,318.66	$985.45	$8,314.74	$6,948.28
38	2023	$481.89	$755.96	$201.11	$1,438.96	$11.35	$6,275.86	$1,044.58	$7,331.79	$5,892.83
39	2024	$627.67	$801.31	$216.47	$1,645.45	$11.80	$6,789.08	$1,107.24	$7,908.12	$6,262.67
TOTALS		$18,599.56	$12,673.43	$3,804.32	$35,077.31	$196.32	$86,253.60	$17,426.23	$103,876.15	$68,798.84
pv@ 9.70%-1985$		$3,707.35	$1,725.15	$556.67	$7,989.37	$21.54	$8,679.30	$2,312.34	$11,013.18	$3,023.81
									GRT= 4.50%	$3,166.29

(a) INCLUDES SUBSEQUENT CAPITAL ADDITIONS
(b) DECOMMISSIONING, SPENT FUEL, INSURANCE, AND IN-REACTOR INTEREST
(c) SOBIS SAVINGS AND SAVINGS BY NOT INCURRING LOAD SHEDDING COSTS

capacity charges

FUEL SAVINGS/W LOAD SHED AND ACID RAIN
ANNUAL REVENUE REQUIREMENTS
MILLIONS$

elim 2 party pur 1994-
2x rate

BREAKEVEN NPV
AT 2006
56.66157363

YEAR		ORIG COST $ADDITIONS CARRYING CHARGES(a) (1)	STATION O&M (2)	OTHER O&M(b) (3)	TOTAL COSTS (4)=(1)+(2)+(3)	O & M AND CAPITAL DIFFERENTIAL FOR SO2 AND NOX (5)	FUEL SAVINGS(c) (6)	CAPACITY CHARGES AVOIDED (7)	TOTAL BENEFITS (8)=(5)+(6)+(7)	BENEFITS LESS COSTS (9)=(8)-(4)
1	1986	$747.27	$79.01	$31.24	$857.52	$0.00	$150.82	$80.57	$231.39	($626.13)
2	1987	$713.90	$85.33	$31.62	$830.85	$0.00	$186.04	$88.78	$274.82	($556.03)
3	1988	$685.60	$93.01	$32.98	$811.59	$0.00	$209.45	$97.23	$306.68	($504.91)
4	1989	$660.09	$101.39	$39.96	$801.44	$0.00	$322.36	$144.03	$466.39	($335.05)
5	1990	$635.23	$110.51	$33.90	$779.64	$0.00	$282.46	$152.68	$435.14	($344.50)
6	1991	$610.30	$117.14	$37.10	$764.54	$0.00	$320.80	$161.84	$482.64	($281.90)
7	1992	$585.46	$124.17	$41.19	$750.82	$0.00	$480.03	$171.54	$651.57	($99.25)
8	1993	$560.69	$131.62	$43.70	$736.01	$2.77	$423.14	$181.84	$607.75	($128.26)
9	1994	$536.03	$139.52	$40.96	$716.51	$2.83	$642.58	$192.75	$838.16	$121.65
10	1995	$511.44	$147.89	$57.53	$716.86	$2.91	$941.02	$204.31	$1,148.24	$431.38
11	1996	$504.40	$156.76	$48.41	$709.57	$3.07	$841.25	$216.57	$1,060.89	$351.32
12	1997	$495.18	$166.17	$51.62	$712.97	$3.04	$880.92	$229.57	$1,113.53	$400.56
13	1998	$486.13	$176.14	$65.36	$727.63	$3.12	$1,239.91	$243.35	$1,486.38	$758.75
14	1999	$477.26	$186.70	$54.99	$718.95	$3.36	$983.57	$257.95	$1,244.88	$525.93
15	2000	$468.59	$197.91	$61.72	$728.22	$3.07	$1,089.07	$273.43	$1,365.57	$637.35
16	2001	$460.10	$209.78	$75.58	$745.46	$3.18	$1,404.47	$289.85	$1,697.50	$952.04
17	2002	$451.84	$222.37	$65.12	$739.33	$3.44	$1,319.72	$307.24	$1,630.40	$891.07
18	2003	$443.83	$235.71	$69.60	$749.14	$4.01	$1,300.48	$325.68	$1,630.17	$881.03
19	2004	$436.03	$249.85	$88.42	$774.30	$4.22	$1,908.58	$345.22	$2,258.02	$1,483.72
20	2005	$428.51	$264.84	$76.04	$769.39	$4.54	$1,526.24	$365.94	$1,896.72	$1,127.33
21	2006	$421.25	$280.73	$81.50	$783.48	$4.77	$1,660.95	$387.90	$2,053.62	$1,270.14
22	2007	$414.35	$297.58	$101.84	$813.77	$5.03	$2,341.24	$411.18	$2,757.45	$1,943.68
23	2008	$407.75	$315.43	$88.98	$812.16	$5.47	$1,967.08	$435.84	$2,408.39	$1,596.23
24	2009	$401.54	$334.36	$94.61	$830.51	$5.78	$2,005.43	$461.98	$2,473.19	$1,642.68
25	2010	$395.74	$354.42	$120.16	$870.32	$6.10	$2,932.42	$489.71	$3,428.23	$2,557.91
26	2011	$390.37	$375.69	$103.97	$870.03	$6.48	$2,420.20	$519.10	$2,945.78	$2,075.75
27	2012	$385.52	$398.23	$111.33	$895.08	$6.72	$2,585.79	$550.25	$3,142.76	$2,247.68
28	2013	$381.21	$422.12	$140.89	$944.22	$6.97	$3,727.72	$583.27	$4,317.96	$3,373.74
29	2014	$377.54	$447.45	$121.90	$946.89	$7.43	$3,215.67	$618.27	$3,841.37	$2,894.48
30	2015	$374.64	$474.30	$130.85	$979.79	$7.72	$3,294.39	$655.37	$3,957.48	$2,977.69
31	2016	$367.56	$502.75	$166.29	$1,036.60	$8.02	$4,969.45	$694.70	$5,672.17	$4,635.57
32	2017	$363.16	$532.92	$143.46	$1,039.54	$8.56	$4,116.48	$736.37	$4,861.41	$3,821.87
33	2018	$361.90	$564.89	$154.33	$1,081.12	$8.89	$4,196.83	$780.55	$4,986.27	$3,905.15
34	2019	$364.73	$598.79	$195.17	$1,158.69	$9.26	$5,891.46	$827.39	$6,728.11	$5,569.42
35	2020	$373.05	$634.71	$170.44	$1,178.20	$9.92	$5,129.18	$877.04	$6,016.14	$4,837.94
36	2021	$390.15	$672.80	$182.35	$1,245.30	$10.30	$5,361.39	$929.67	$6,301.36	$5,056.06
37	2022	$421.66	$713.17	$231.63	$1,366.46	$10.71	$7,966.96	$985.45	$8,963.12	$7,596.66
38	2023	$481.89	$755.96	$201.11	$1,438.96	$11.48	$6,680.20	$1,044.58	$7,736.26	$6,297.30
39	2024	$627.67	$801.31	$216.47	$1,645.45	$11.97	$7,375.02	$1,107.24	$8,494.23	$6,848.78
TOTALS		$18,599.56	$12,673.43	$3,804.32	$35,077.31	$195.14	$94,290.77	$17,426.23	$111,912.14	$76,834.83
pv@ 9.70%-1985$		$5,707.55	$1,725.15	$556.67	$7,989.37	$21.41	$9,465.88	$2,312.34	$11,799.63	$3,810.26
									SRT= 4.50%	$3,989.80

(a) INCLUDES SUBSEQUENT CAPITAL ADDITIONS
(b) DECOMMISSIONING, SPENT FUEL, INSURANCE, AND IN-REACTOR INTEREST
(c) SOBIG SAVINGS AND SAVINGS BY NOT INCURRING LOAD SHEDDING COSTS

To determine the revenue requirements associated with no increase or a 50% increase in PJM capacity charges and the resulting net benefits in the Limerick life cycle analysis, it is necessary to reduce column (7) data shown on pages 1 and 2 by one-half or three quarters respectively. The table shown below summarizes the six variations reviewed by Dr. Hieronymus.

Net Present Value of Benefits
With Limerick 1 In Service
Billions $

	0% Increase in PJM Capacity Charges	50% Increase in PJM Capacity Charges	100% increase in PJM Capacity Charges
50% reduction in two-party purchases	2.0	2.6	3.2
Elimination of two-party purchases	2.8	3.4	4.0

REVENUE REQUIREMENTS

MILLIONS $

9/3/85

YEAR		DECOM REV REQ (1)	SPENT FUEL GENERATION MWH (2)	N/G SPENT FUEL 1.04 (3)	INSURANCE PROPCOV 1.06 (4)	INSURANCE LIABILITY 1.06 (5)	INSURANCE REPL POWER (6)	TOTAL INSURANCE (7)=(4)+(5)+(6)	IN REACTOR INTEREST (8)	TOTAL LIKE OTHER O&M (9)=(1)+(3) +(7)+(8)
1	1986	$3.16	5245600	$5.46	$5.00	$0.70	$1.50	$7.20	$15.42	$31.24
2	1987	$3.16	5699100	$5.93	$5.25	$0.74	$1.50	$7.49	$15.04	$31.62
3	1988	$3.16	5764600	$6.00	$5.57	$0.78	$1.50	$7.85	$15.97	$32.98
4	1989	$3.16	7522300	$7.82	$5.90	$0.83	$1.50	$8.23	$20.75	$39.96
5	1990	$3.16	5460700	$5.68	$6.25	$0.88	$1.50	$8.63	$16.43	$33.90
6	1991	$3.16	5543100	$5.76	$6.63	$0.93	$1.50	$9.06	$19.12	$37.10
7	1992	$3.16	7281800	$7.57	$7.03	$0.99	$1.50	$9.52	$20.94	$41.19
8	1993	$3.16	5342500	$5.56	$7.45	$1.05	$1.50	$10.00	$24.98	$43.70
9	1994	$3.16	5524100	$5.75	$7.90	$1.11	$1.50	$10.51	$21.54	$40.96
10	1995	$3.16	7334400	$7.63	$8.37	$1.18	$1.50	$11.05	$35.69	$57.53
11	1996	$3.16	5450000	$5.67	$8.87	$1.25	$1.50	$11.62	$27.96	$48.41
12	1997	$3.16	5471300	$5.69	$9.40	$1.33	$1.50	$12.23	$30.54	$51.62
13	1998	$3.16	7252100	$7.54	$9.96	$1.41	$1.50	$12.87	$41.79	$65.36
14	1999	$3.16	5321400	$5.53	$10.56	$1.49	$1.50	$13.55	$32.75	$54.99
15	2000	$3.16	5804600	$6.04	$11.19	$1.58	$1.50	$14.27	$38.25	$61.72
16	2001	$3.16	7241600	$7.53	$11.86	$1.67	$1.50	$15.03	$49.86	$75.58
17	2002	$3.16	5462800	$5.68	$12.57	$1.77	$1.50	$15.84	$40.44	$65.12
18	2003	$3.16	5593600	$5.82	$13.32	$1.88	$1.50	$16.70	$43.92	$69.60
19	2004	$3.16	7203800	$7.49	$14.12	$1.99	$1.50	$17.61	$60.16	$88.42
20	2005	$3.16	5469100	$5.69	$14.97	$2.11	$1.50	$18.58	$48.61	$76.04
21	2006	$3.16	5597800	$5.82	$15.87	$2.24	$1.50	$19.61	$52.91	$81.50
22	2007	$3.16	7178400	$7.47	$16.82	$2.37	$1.50	$20.69	$70.52	$101.84
23	2008	$3.16	5492600	$5.71	$17.83	$2.51	$1.50	$21.84	$58.27	$88.98
24	2009	$3.16	5598000	$5.82	$18.90	$2.66	$1.50	$23.06	$62.57	$94.61
25	2010	$3.16	7178500	$7.47	$20.03	$2.82	$1.50	$24.35	$85.18	$120.16
26	2011	$3.16	5469100	$5.69	$21.23	$2.99	$1.50	$25.72	$69.40	$103.97
27	2012	$3.16	5621100	$5.85	$22.50	$3.17	$1.50	$27.17	$75.15	$111.33
28	2013	$3.16	7178200	$7.47	$23.85	$3.36	$1.50	$28.71	$101.55	$140.89
29	2014	$3.16	5467200	$5.69	$25.28	$3.56	$1.50	$30.34	$82.71	$121.90
30	2015	$3.16	5598000	$5.82	$26.80	$3.77	$1.50	$32.07	$89.80	$130.85
31	2016	$3.16	7203800	$7.49	$28.41	$4.00	$1.50	$33.91	$121.73	$166.29
32	2017	$3.16	5471300	$5.69	$30.11	$4.24	$1.50	$35.85	$98.76	$143.46
33	2018	$3.16	5595800	$5.82	$31.92	$4.49	$1.50	$37.91	$107.44	$154.33
34	2019	$3.16	7178200	$7.47	$33.84	$4.76	$1.50	$40.10	$144.44	$195.17
35	2020	$3.16	5432400	$5.71	$35.87	$5.05	$1.50	$42.42	$119.15	$170.44
36	2021	$3.16	5595900	$5.82	$38.02	$5.35	$1.50	$44.87	$128.50	$182.35
37	2022	$3.16	7178400	$7.47	$40.30	$5.67	$1.50	$47.47	$173.53	$231.63
38	2023	$3.16	5471300	$5.69	$42.72	$6.01	$1.50	$50.23	$142.03	$201.11
39	2024	$3.16	5619000	$5.84	$45.28	$6.37	$1.50	$53.15	$154.32	$216.47
		$123.24		$245.65	$717.75	$101.06	$58.50	$877.31	$2,358.12	$3,804.32

1987 1.05

1988 1.06

PROJECT: T210LAJ MEMBER: OUTPUT DATE: 85/08/30
GROUP: SOBIG2 LEVEL: 01.00 TIME: 16:15
TYPE: DATA USERID: T210LCG PAGE: 01 OF 01

OUTPUT

START COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8

4 LIMERICK 01 RATE CASE: RESULTS OF 8/28 & 8/29/85 SOBIG RUNS USING
27 8/28/85 REVISED NUCLEAR FUEL COST ESTIMATES.
1 BELOW IS THE IN-REACTOR INTEREST FOR LIMERICK 01
1 ----------

YEAR	FUEL COST ($/MILLION)	BURN-UP (C/MBTU)	INTEREST	[illegible] ($ X MILLIONS)
1985	11.17	78.00	27.00	3.67
1986	50.54	78.00	27.00	17.49
1987	39.47	63.00	24.00	15.04
1988	30.02	47.00	25.00	15.97
1989	39.84	48.00	25.00	20.75
1990	29.82	49.00	27.00	16.43
1991	33.93	55.00	31.00	19.12
1992	46.72	58.00	26.00	20.94
1993	39.85	67.00	42.00	24.98
1994	43.07	70.00	35.00	21.54
1995	61.64	76.00	44.00	35.69
1996	49.23	81.00	46.00	27.96
1997	51.91	85.00	58.00	30.54
1998	73.15	91.00	52.00	41.79
1999	57.17	96.00	55.00	32.75
2000	66.13	102.00	59.00	38.25
2001	86.86	108.00	62.00	49.86
2002	69.85	114.00	66.00	40.44
2003	75.92	121.00	70.00	43.92
2004	102.68	128.00	75.00	60.16
2005	83.68	136.00	79.00	48.61
2006	90.70	144.00	84.00	52.91
2007	122.61	153.00	88.00	70.52
2008	100.43	162.00	94.00	58.27
2009	108.70	172.00	99.00	62.57
2010	146.26	182.00	106.00	85.18
2011	119.59	193.00	112.00	69.40
2012	130.66	205.00	118.00	76.15
2013	174.90	217.00	126.00	101.55
2014	143.03	230.00	133.00	82.71
2015	155.40	244.00	141.00	89.80
2016	209.37	258.00	150.00	121.73
2017	171.26	274.00	158.00	98.76
2018	185.46	290.00	168.00	107.44
2019	249.93	308.00	178.00	144.44
2020	205.81	326.00	189.00	119.15
2021	222.30	346.00	200.00	128.50
2022	298.17	366.00	213.00	173.53
2023	244.93	388.00	225.00	142.03
2024	267.14	412.00	238.00	154.32

Lim 1 Pre 6 post Commercial Split

1986 Total generation 6090100 MWH
less Jan '86 534,500 precomm.
less Feb '86 310,000 precomm
5,245,600 MWH (post commercial gen in 1986)

1986 Fuel Savings 179.82 million
less precomm fuel sav 29 million
1986 post commercial fuel SAVINGS 150.82 million

1986 Post commercial in reactor interest
Lim 1 1986 fuel cost 50.54 million
less JAN '86 3.67 million
less Feb '86 $\left(\frac{310{,}000 \text{ MWH}}{5{,}245{,}600 \text{ MWH}}\right)$ X 38 mill 2.33 "
44.54 million post commer fuel cost

$\therefore \frac{27}{78}$ (percent $/MBTU) X 44.54 mill = 15.42 million post commercial in reactor interest

Carrying $/MBTU

corl

REVENUE REQUIREMENTS
FROM CARRYING CHARGES
LIMI & 50% COMMON
MILLIONS

INCL Land Rev Reg

ATTACHMENT
IR-OCA-2-25b
ITEM 3
5 Page

ORIGCOST AND ADDIT	$3,176.476	$4.189	$12.781	$13.657	$14.592	$15.578	$16.639	$17.772	$18.980	$20.271	$21.489
VINTAGE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
1	$746.52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$712.25	$0.90									
3	$681.23	$0.85	$2.77								
4	$652.98	$0.80	$2.59	$2.97							
5	$625.33	$0.75	$2.44	$2.78	$3.18						
6	$597.54	$0.71	$2.30	$2.61	$2.98	$3.41					
7	$569.76	$0.67	$2.17	$2.47	$2.80	$3.19	$3.65				
8	$541.98	$0.62	$2.03	$2.32	$2.65	$3.00	$3.42	$3.92			
9	$514.20	$0.58	$1.90	$2.18	$2.49	$2.83	$3.22	$3.67	$4.21		
10	$486.41	$0.54	$1.77	$2.04	$2.34	$2.65	$3.03	$3.45	$3.94	$4.51	
11	$476.12	$0.49	$1.64	$1.89	$2.18	$2.50	$2.85	$3.25	$3.70	$4.22	$4.81
12	$463.54	$0.48	$1.50	$1.75	$2.02	$2.33	$2.67	$3.06	$3.48	$3.97	$4.50
13	$450.97	$0.47	$1.48	$1.60	$1.87	$2.16	$2.49	$2.85	$3.27	$3.73	$4.22
14	$438.39	$0.45	$1.43	$1.57	$1.7[illegible]	$1.99	$2.3[illegible]	$2.67	$3.06	$3.51	$3.97
15	$425.81	$0.45	$1.39	$1.53	$1.68	$1.83	$2.13	$2.47	$2.85	$3.28	$3.73
16	$413.24	$0.43	$1.35	$1.48	$1.63	$1.79	$1.95	$2.28	$2.64	$3.05	$3.49
17	$400.66	$0.42	$1.31	$1.44	$1.58	$1.73	$1.9[illegible]	$2.08	$2.43	$2.83	$3.24
18	$388.09	$0.40	$1.27	$1.39	$1.53	$1.68	$1.85	$2.03	$2.22	$2.60	$3.00
19	$375.51	$0.39	$1.22	$1.34	$1.48	$1.62	$1.79	$1.97	$2.17	$2.37	$2.76
20	$362.94	$0.38	$1.18	$1.30	$1.43	$1.57	$1.72	$1.90	$2.10	$2.3[illegible]	$2.51
21	$350.36	$0.36	$1.14	$1.25	$1.37	$1.51	$1.66	$1.83	$2.02	$2.23	$2.44
22	$337.79	$0.35	$1.10	$1.20	$1.32	$1.45	$1.60	$1.77	$1.95	$2.15	$2.35
23	$325.21	$0.34	$1.06	$1.16	$1.27	$1.40	$1.54	$1.70	$1.87	$2.06	$2.26
24	$312.63	$0.32	$1.02	$1.11	$1.22	$1.34	$1.48	$1.63	$1.80	$1.98	$2.16
25	$300.06	$0.31	$0.97	$1.07	$1.17	$1.29	$1.42	$1.56	$1.73	$1.90	$2.09
26	$287.48	$0.30	$0.93	$1.02	$1.12	$1.23	$1.36	$1.50	$1.65	$1.82	$2.00
27	$274.91	$0.28	$0.89	$0.98	$1.07	$1.18	$1.30	$1.43	$1.58	$1.74	$1.91
28	$262.33	$0.27	$0.85	$0.93	$1.03	$1.12	$1.24	$1.36	$1.50	$1.65	$1.82
29	$249.76	$0.26	$0.80	$0.89	$0.97	$1.07	$1.18	$1.30	$1.43	$1.57	$1.73
30	$237.18	$0.24	$0.76	$0.84	$0.92	$1.01	$1.11	$1.23	$1.35	$1.49	$1.64
31	$224.61	$0.23	$0.72	$0.79	$0.87	$0.96	$1.05	$1.16	$1.28	$1.41	$1.55
32	$212.03	$0.22	$0.68	$0.75	$0.83	$0.90	$0.99	$1.09	$1.21	$1.33	$1.46
33	$199.45	$0.20	$0.64	$0.70	$0.77	$0.85	$0.93	$1.03	$1.13	$1.25	$1.37
34	$186.88	$0.19	$0.60	$0.65	$0.72	$0.79	$0.87	$0.96	$1.06	$1.16	$1.28
35	$174.30	$0.18	$0.55	$0.61	$0.68	$0.73	$0.81	$0.89	$0.98	$1.08	$1.19
36	$161.73	$0.16	$0.51	$0.56	$0.61	$0.68	$0.75	$0.82	$0.91	$1.00	$1.10
37	$149.15	$0.15	$0.47	$0.52	$0.56	$0.62	$0.69	$0.76	$0.83	$0.92	$1.01
38	$136.58	$0.13	$0.43	$0.47	$0.51	$0.57	$0.63	$0.69	$0.76	$0.84	$0.92
39	$124.00	$0.12	$0.38	$0.43	$0.46	$0.51	$0.57	$0.62	$0.69	$0.75	$0.83
	$14,829.91	$15.40	$46.25	$48.59	$50.98	$53.50	$56.17	$58.94	$61.80	$64.72	$67.36
By a											
9.7[illegible]	$5,356.76	$5.41	$15.03	$14.62	$14.22	$13.83	$13.43	$13.07	$12.71	$12.3[illegible]	$11.9[illegible]

[illegible]ecome last four years of additions reflect decreasing amounts of itc
itc due to short lived facilities

$22.780	$24.144	$25.593	$27.125	$28.753	$30.485	$32.312	$34.243	$36.301	$38.484	$40.794	$43.240	$45.832
1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$5.13												
$4.60	$5.46											
$4.50	$5.11	$5.63										
$4.23	$4.79	$5.45	$6.22									
$3.97	$4.50	$5.10	$5.81	$5.64								
$3.7[illegible]	$4.22	$4.80	$5.44	$6.20	$7.03							
$3.45	$3.94	$4.50	$5.1[illegible]	$5.8[illegible]	$6.62	$7.59						
$3.18	$3.66	$4.19	$4.75	$5.45	$6.20	$7.08	$8.11					
$2.92	$3.36	$3.85	$4.46	$5.10	$5.81	$6.62	$7.56	$8.69				
$2.66	$3.10	$3.59	$4.13	$4.75	$5.43	$6.20	$7.07	$8.09	$9.31			
$2.55	$2.82	$3.26	$3.81	$4.39	$5.08	$5.79	$6.62	$7.56	$8.67	$9.99		
$2.49	$2.73	$3.16	$3.46	$4.04	$4.67	$5.38	$6.16	$7.07	$8.09	$9.29	$10.73	
$2.35	$2.62	$2.65	$3.16	$3.65	$4.25	$4.97	$5.73	$6.55	$7.52	$8.65	$9.93	$11.54
$2.25	$2.52	$2.77	$3.05	$3.54	$3.93	$4.56	$5.25	$6.11	$7.04	$8.09	$9.25	$10.72
$2.15	$2.41	$2.65	$2.92	$3.23	$3.54	$4.15	$4.85	$5.63	$6.52	$7.52	$8.66	$9.95
$2.09	$2.30	$2.53	$2.79	$3.08	$3.41	$3.74	$4.40	$5.15	$6.00	$6.96	$8.05	$9.23
$1.99	$2.19	$2.41	$2.66	$2.94	$3.25	$3.60	$3.96	$4.67	$5.48	$6.39	$7.43	$8.62
$1.85	$2.08	$2.30	$2.52	$2.79	$3.09	$3.42	$3.80	$4.19	$4.95	$5.82	$6.81	$7.94
$1.80	$1.96	$2.16	$2.40	$2.65	$2.93	$3.25	$3.60	$4.01	$4.43	$5.25	$6.15	$7.27
$1.70	$1.87	$2.06	$2.27	$2.50	$2.77	$3.07	$3.40	$3.79	$4.23	$4.69	$5.57	$6.59
$1.60	$1.76	$1.94	$2.13	$2.36	$2.61	$2.89	$3.21	$3.57	$3.99	$4.45	$4.95	$5.92
$1.50	$1.65	$1.82	$2.00	$2.21	$2.45	$2.71	$3.01	$3.35	$3.74	$4.18	$4.70	$5.24
$1.40	$1.54	$1.70	$1.87	$2.07	$2.29	$2.53	$2.81	$3.13	$3.50	$3.91	$4.39	$4.94
$1.30	$1.44	$1.58	$1.74	$1.92	$2.13	$2.35	$2.62	$2.91	$3.25	$3.64	$4.08	$4.60
$1.21	$1.33	$1.46	$1.61	$1.78	$1.97	$2.18	$2.42	$2.69	$3.01	$3.36	$3.77	$4.25
$1.11	$1.22	$1.34	$1.48	$1.63	$1.81	$2.00	$2.22	$2.47	$2.75	$3.09	$3.47	$3.90
$1.01	$1.11	$1.22	$1.35	$1.45	$1.65	$1.82	$2.02	$2.25	$2.51	$2.81	$3.16	$3.56
$0.91	$1.00	$1.10	$1.22	$1.34	$1.45	$1.64	$1.83	$2.03	$2.27	$2.54	$2.85	$3.21
$70.00	$72.74	$75.56	$78.43	$81.40	$84.47	$87.55	$90.71	$93.95	$97.31	$100.65	$104.09	$107.57
$11.50	$11.03	$10.69	$10.31	$9.94	$9.53	$9.24	$8.91	$8.59	$8.28	$7.97	$7.68	$7.40

$48.533	$51.491	$54.587	$57.863	$61.327	$65.012	$68.917	$73.042	$77.430	$82.070	$87.004	$92.221	$97.753
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

$12.43												
$11.84	$13.43											
$10.73	$12.45	$14.53										
$9.56	$11.55	$13.46	$15.77									
$8.24	$10.73	$12.46	$14.59	$17.18								
$8.50	$9.93	$11.57	$13.51	$15.88	$18.63							
$7.76	$5.10	$10.67	$12.50	$14.67	$17.35	$15.68						
$7.03	$8.29	$9.77	$11.50	$13.54	$16.00	$15.52	$17.75					
$6.26	$7.47	$8.67	$10.50	$12.43	$14.73	$15.62	$17.79	$20.58				
$5.54	$6.66	$7.97	$9.50	$11.32	$13.46	$15.62	$17.79	$20.58	$24.28			
$5.20	$5.85	$7.07	$8.50	$10.20	$12.23	$15.62	$17.79	$20.58	$24.28	$29.43		
$4.81	$5.46	$6.17	$7.51	$9.09	$10.99	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81	
$4.41	$5.01	$5.72	$6.51	$7.97	$9.72	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81	$51.68
$4.02	$4.57	$5.21	$5.99	$6.85	$8.47	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81	$51.68
$3.63	$4.12	$4.71	$5.40	$6.25	$7.22	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81	$51.68

$111.09	$114.61	$118.20	$121.78	$125.35	$128.92	$140.58	$142.32	$144.08	$145.82	$147.15	$151.24	$155.64
$7.13	$6.86	$6.61	$6.36	$6.12	$5.89	$5.66	$5.44	$5.23	$5.03	$4.83	$4.72	$4.62

$103.622 2023	$109.836 2024	TOTAL YEAR BY YEAR REVENUE REQ ON COST	LAND REV REQ	TOTAL REV REQ
$0.00	$0.00	$746.52	$0.75	$747.27
		$713.15	$0.75	$713.90
		$684.85	$0.75	$685.60
		$659.34	$0.75	$660.09
		$634.48	$0.75	$635.23
		$609.55	$0.75	$610.30
		$584.71	$0.75	$585.46
		$559.94	$0.75	$560.69
		$535.28	$0.75	$536.03
		$510.69	$0.75	$511.44
		$503.65	$0.75	$504.40
		$494.43	$0.75	$495.18
		$485.38	$0.75	$486.13
		$476.51	$0.75	$477.26
		$467.84	$0.75	$468.59
		$459.35	$0.75	$460.10
		$451.09	$0.75	$451.84
		$443.08	$0.75	$443.83
		$435.28	$0.75	$436.03
		$427.76	$0.75	$428.51
		$420.50	$0.75	$421.25
		$413.60	$0.75	$414.35
		$407.00	$0.75	$407.75
		$400.79	$0.75	$401.54
		$394.99	$0.75	$395.74
		$389.62	$0.75	$390.37
		$384.77	$0.75	$385.52
		$380.46	$0.75	$381.21
		$376.79	$0.75	$377.54
		$373.89	$0.75	$374.64
		$366.81	$0.75	$367.56
		$362.41	$0.75	$363.16
		$361.15	$0.75	$361.90
		$363.98	$0.75	$364.73
		$372.30	$0.75	$373.05
		$389.40	$0.75	$390.15
		$420.91	$0.75	$421.66
$80.14		$481.14	$0.75	$481.89
$80.14	$165.26	$626.92	$0.75	$627.67
$160.26	$165.26	$18,570.31	$29.25	$18,599.56
$4.54	$4.47	cc		

Land revenue requirement
= $3,675,000 * .2035 ↓ 50% of land
→ next page

Applicable & Unblended Marginal Fed

1. Cost of Money

	Target Capitalization Rate	Average Incremental Cost of Money 1962–2020	Weighted Cost of Money
Long-Term Debt	50%	12.09%	6.04%
Preferred Stock	12	12.09	1.45
Common Stock	38	13.94	5.30
Total	100%		12.79%

2. Income Taxes on Equity Components of Cost of Money

$$= (\text{cost of preferred} + \text{cost (common)}) \times \frac{\text{Tax Rate}}{(1 - \text{Tax Rate})}$$

$$= (1.45\% + 5.30\%) \times \frac{51.13\%}{(1 - 51.13\%)}$$

$$= 7.06\%$$

3. Capital Stock Tax

$$= (\% \text{ of preferred} + \% \text{ of common}) \times \text{Tax Rate}$$

$$= (12\% + 38\%) \times 1\%$$

$$= 0.50\%$$

4. Total

$$= 12.79\% + 7.06\% + 0.50\% = 20.35\%$$

MILLIONS OF DOLLARS

50% REDUCTION IN 2 PARTY PURCHASES STARTING 1994

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	NOX FACILITIES O&M			SO2 FACILITIES O&M				SO2 FACILITIES CAP CHARGES	TOTAL (1)+(2)+(3)+(4)
	W/LIM	W/O LIM	NET BENEFIT(1)	W/LIM	W/O LIM	NET BENEFIT(2)	1993ADD(3)	2000ADD(4)	
1993	0.00	0.00	0.00	0.98	2.09	1.11	1.66	0.00	2.77
1994	0.00	0.00	0.00	1.03	2.20	1.17	1.66	0.00	2.83
1995	0.00	0.00	0.00	1.10	2.35	1.25	1.66	0.00	2.91
1996	0.00	0.00	0.00	1.23	2.64	1.41	1.66	0.00	3.07
1997	0.00	0.00	0.00	1.21	2.59	1.38	1.66	0.00	3.04
1998	0.00	0.00	0.00	1.28	2.74	1.46	1.66	0.00	3.12
1999	0.00	0.00	0.00	1.50	3.20	1.70	1.66	0.00	3.36
2000	0.00	0.00	0.00	7.31	8.88	1.57	1.66	-0.16	3.07
2001	0.00	0.00	0.00	7.79	9.47	1.68	1.66	-0.16	3.18
2002	0.00	0.00	0.00	9.00	10.94	1.94	1.66	-0.16	3.44
2003	0.00	0.39	0.39	8.65	10.52	1.87	1.66	-0.16	3.76
2004	1.01	1.87	0.86	9.00	10.95	1.95	1.66	-0.16	4.31
2005	2.51	3.52	1.01	9.85	11.98	2.13	1.66	-0.16	4.64
2006	4.19	5.36	1.17	10.27	12.48	2.21	1.66	-0.16	4.88
2007	6.05	7.41	1.36	10.64	12.94	2.30	1.66	-0.16	5.16
2008	8.13	9.69	1.56	11.85	14.40	2.55	1.66	-0.16	5.61
2009	10.43	12.22	1.79	12.30	14.95	2.65	1.66	-0.16	5.94
2010	12.99	15.01	2.02	12.74	15.49	2.75	1.66	-0.16	6.27
2011	15.33	17.45	2.12	14.01	17.03	3.02	1.66	-0.16	6.64
2012	17.91	20.14	2.23	14.61	17.76	3.15	1.66	-0.16	6.88
2013	20.74	23.08	2.34	15.22	18.50	3.28	1.66	-0.16	7.12
2014	23.85	26.30	2.45	16.74	20.35	3.61	1.66	-0.16	7.56
2015	27.25	29.83	2.58	17.44	21.20	3.76	1.66	-0.16	7.84
2016	30.98	33.69	2.71	18.12	22.03	3.91	1.66	-0.16	8.12
2017	35.06	37.90	2.84	19.87	24.16	4.29	1.66	-0.16	8.63
2018	39.51	42.49	2.98	20.67	25.13	4.46	1.66	-0.16	8.94
2019	44.38	47.50	3.12	21.59	26.25	4.66	1.66	-0.16	9.28
2020	49.68	52.96	3.28	23.81	28.95	5.14	1.66	-0.16	9.92
2021	55.47	58.90	3.43	24.71	30.03	5.32	1.66	-0.16	10.25
2022	61.76	65.37	3.61	25.58	31.10	5.52	1.66	-0.16	10.63
2023	68.62	72.39	3.77	28.19	34.27	6.08	1.66	-0.16	11.35
2024	76.07	80.03	3.96	29.39	35.73	6.34	1.66	-0.16	11.80
	611.92	663.50	51.58	407.68	503.30	95.62	53.12	-4.00	196.32
			51.58						

SO2 ADDITIONS, DIFF BET W AND W/O LIM

1993	2000	
9.74	-0.94	additions difference
0.17	0.17	CCR, PER TP+-RNR
1.66	-0.16	REV REQ

MILLIONS OF DOLLARS

ELIMINATE 2 PARTY PURCHASES STARTING 1994

	NOX FACILITIES O&M			SO2 FACILITIES O&M			SO2 FACILITIES CAP CHARGES		TOTAL (1)+(2)+(3)+(4)
	W/LIM	W/O LIM	NET BENEFIT(1)	W/LIM	W/O LIM	NET BENEFIT(2)	1993ADD(3)	2000ADD(4)	
1993	0.00	0.00	0.00	0.98	2.09	1.11	1.66	0.00	2.77
1994	0.00	0.00	0.00	1.03	2.20	1.17	1.66	0.00	2.83
1995	0.00	0.00	0.00	1.10	2.35	1.25	1.66	0.00	2.91
1996	0.00	0.00	0.00	1.23	2.64	1.41	1.66	0.00	3.07
1997	0.00	0.00	0.00	1.21	2.59	1.38	1.66	0.00	3.04
1998	0.00	0.00	0.00	1.28	2.74	1.46	1.66	0.00	3.12
1999	0.00	0.00	0.00	1.50	3.20	1.70	1.66	0.00	3.36
2000	0.00	0.00	0.00	7.31	8.88	1.57	1.66	-0.16	3.07
2001	0.00	0.00	0.00	7.79	9.47	1.68	1.66	-0.16	3.18
2002	0.00	0.00	0.00	9.00	10.94	1.94	1.66	-0.16	3.44
2003	0.71	1.35	0.64	8.65	10.52	1.87	1.66	-0.16	4.01
2004	2.22	2.99	0.77	9.00	10.95	1.95	1.66	-0.16	4.22
2005	3.90	4.81	0.91	9.85	11.98	2.13	1.66	-0.16	4.54
2006	5.79	6.85	1.06	10.27	12.48	2.21	1.66	-0.16	4.77
2007	7.88	9.11	1.23	10.64	12.94	2.30	1.66	-0.16	5.03
2008	10.20	11.62	1.42	11.85	14.40	2.55	1.66	-0.16	5.47
2009	12.77	14.40	1.63	12.30	14.95	2.65	1.66	-0.16	5.78
2010	15.62	17.47	1.85	12.74	15.49	2.75	1.66	-0.16	6.10
2011	18.15	20.11	1.96	14.01	17.03	3.02	1.66	-0.16	6.48
2012	20.93	23.00	2.07	14.61	17.76	3.15	1.66	-0.16	6.72
2013	23.98	26.17	2.19	15.22	18.50	3.28	1.66	-0.16	6.97
2014	27.32	29.64	2.32	16.74	20.35	3.61	1.66	-0.16	7.43
2015	30.97	33.43	2.46	17.44	21.20	3.76	1.66	-0.16	7.72
2016	34.96	37.57	2.61	18.12	22.03	3.91	1.66	-0.16	8.02
2017	39.32	42.09	2.77	19.87	24.16	4.29	1.66	-0.16	8.56
2018	44.08	47.01	2.93	20.67	25.13	4.46	1.66	-0.16	8.89
2019	49.27	52.37	3.10	21.59	26.25	4.66	1.66	-0.16	9.26
2020	54.92	58.20	3.28	23.81	28.95	5.14	1.66	-0.16	9.92
2021	61.07	64.55	3.48	24.71	30.03	5.32	1.66	-0.16	10.30
2022	67.76	71.45	3.69	25.58	31.10	5.52	1.66	-0.16	10.71
2023	75.04	78.94	3.90	28.19	34.27	6.08	1.66	-0.16	11.48
2024	82.94	87.07	4.13	29.39	35.73	6.34	1.66	-0.16	11.97
	689.80	740.20	50.40	407.66	503.30	95.62	53.12	-4.00	195.14
			50.40						

SO2 ADDITIONS, DIFF BET W AND W/O LIM

1993	2000	
9.74	-0.94	additions difference
0.17	0.17	ECR, PER TPH-RNR
1.66	-0.16	REV REQ

Table 1

SO_2 Pollution Control Costs for Existing Coal Plants

Capital Costs
$/KW
(1984$)

Unit Size (MW)	Sulfur Content (lbs. SO_2/mmBtu)				
	1.6	2.50	3.33	4.00	5.00
150	315	328	349	365	380
200	292	304	324	340	357
300	257	267	285	300	313
400	227	237	255	269	280
500	200	209	225	237	252

SUPPLIED BY PHB

Table 2

SO_2 Pollution Control Costs for Existing Coal Plants

O&M Cost
Mills/KWh
(1984$)

Unit Size (MW)	Sulfur Content (lbs. SO_2/mmBtu)				
	1.6	2.50	3.33	4.00	5.00
150	5.3	6.1	6.7	7.0	7.5
200	5.1	5.9	6.4	6.7	7.2
300	4.7	5.4	6.0	6.3	6.7
400	4.4	5.1	5.6	5.9	6.3
500	4.1	4.8	5.3	5.6	6.0

SUPPLIED BY PHB

Table 3

SO_2 Pollution Control Costs for Existing Coal Plants

Capacity Penalty (%)

Unit Size (MW)	Sulfur Content (lbs. SO_2/mmBtu)				
	1.6	2.50	3.33	4.00	5.00
150	3.7	4.0	4.2	4.3	4.4
200	3.7	4.0	4.2	4.4	4.5
300	3.7	4.0	4.2	4.3	4.4
400	3.6	3.9	4.1	4.3	4.4
500	3.6	3.9	4.1	4.3	4.4

SUPPLIED BY PHB

Limestone FGD Capital and O&M Cost Assumptions for New Coal Plants ($1984)

Design Basis

2 X 525 MW Capacity New
406 TPH Coal Burn (Gilbert, 12,670 Btu/lb)
1%, 2%, 2.7% Sulfur Coal
100% Sulfur Reports to Stack
90% SO_2 Removal
1 1.15 SO_2 to $CaCO_3$ Stoichiometry
Forced Oxidation
60° F Reheat
70% Capacity Factor
$20/ton Sludge Disposal (typical of Pennsylvania and $5/ton less than PECO would incur at Chester)

Capital Cost

% Sulfur in Coal	Direct Capital Cost $/kw	Source
1.0	213	JSM database
2.0	234	JSM database
2.7	253	Gilbert cost estimate (Chester)

O&M Cost

% Sulfur in Coal	O&M, Mills/kWh Fixed	Variable	Total	Source
1.0	1.22	2.68	3.90	JSM Calc'n
2.0	1.43	3.74	5.17	JSM Calc'n
2.7	1.52	4.52	6.04	JSM Calc'n

Source: Jim S. MacKenzie
United Engineering & Constructions, Inc.

SUPPLIED BY PAB

Table 1 (continued)

PRELIMINARY ESTIMATES OF
LEVELIZED COSTS IN REAL TERMS IN
1984 DOLLARS FOR THE PERIOD 1993-2024

FUEL COST EFFECTS ($/MMBtu)

Unit Name	Company	NERA Code	Acid Rain Effect On Fuel Costs Given Lim. 1 1/	Effect of Lim. 1 On Fuel Costs Given Acid Rain 2/
Montour 1,2	Penn. Pwr. & Lt.	BMMR	0.36013	0.00000
Keystone 1,2	GPU: Penn. Elec. Co.	BMKI	0.00000	0.00000
Conemaugh 1,2	GPU: Penn. Elec. Co.	BMNB	0.00000	0.00000
Williamsberg 5	GPU: Penn. Elec. Co.	BMWJ	0.36013	0.00000
Homer 1-3	GPU: Penn. Elec. Co.	BMHC	0.00000	0.00000
Shawville 1-4	GPU: Penn. Elec. Co.	BMSK	0.36013	0.00000
Seward 4	GPU: Penn. Elec. Co.	BMWL	0.00000	0.00000
Seward 5	GPU: Penn. Elec. Co.	BMWM	0.00000	0.00000
Warren 1,2	GPU: Penn. Elec. Co.	BMWN	0.36013	0.00000
Front 1-5	GPU: Penn. Elec. Co.	BMWO	0.36013	0.00000
Portland 1,2	GPU: Metropolitan Edison Co.	BMWP	0.36013	0.00000
Titus 1-3	GPU: Metropolitan Edison Co.	BMWQ	0.32684	0.00000
Generic Coal Units	"GENERIC EASTERN"	BCEA	-0.01996	0.00000
Generic Coal Units	"GENERIC WESTERN"	BCWA	-0.00918	0.00000
Generic Coal Units	"GENERIC SOUTHERN"	BCSA	-0.01996	0.00000

SUPPLIED BY PHB

1/ These costs should be added, starting in 1993, to the fuel costs in the current base case with Limerick 1. This will give the case for acid rain with Limerick 1.

2/ These costs should be added, starting in 1993, to the fuel costs from the modified base case with Limerick 1 (i.e. Limerick 1 with acid rain). This will give the case for acid rain without Limerick 1.

Table 2

PRELIMINARY ESTIMATES OF
LEVILIZED COSTS IN REAL TERMS IN
1984 DOLLARS FOR THE PERIOD 1993-2024

VARIABLE COST EFFECTS (mills/kWh)

Unit Name	Acid Rain Effect On Variable O&M Given Lim. 1 [1]	Effect of Lim. 1 On Variable O&M Given Acid Rain [2]
BCEA [3]	0.47573	0.00000
BCWA [3]	0.14162	0.00000
BNEH [4]	0.00000	1.73883
BNSH [4]	0.00000	.26066
BCSA [3]	0.47573	-0.00016
BNSC [4]	2.19269	1.22484
BNWB [4]	1.28662	.26050

1/ These costs should be added, starting in 1993, to the variable O&M costs in the current base case with Limerick 1. This will give the case for acid rain with Limerick 1.

2/ These costs should be added, starting in 1993, to the variable O&M costs from the modified base case with Limerick 1 (i.e. Limerick 1 with acid rain). This will give the case for acid rain without Limerick 1.

3/ Future Generic Coal Plant

4/ Retrofitted Coal Plant

SUPPLIED BY PHB

TABLE 3

CAPACITY ADJUSTMENTS
(In Percent)

Unit Name	Acid Rain Effect On Capacity Given Limerick 1		Effect Of Limerick 1 And Acid Rain On Capacity 1/	
	1993	2000	1993	2000
BNWB	-0.29	-1.43	-0.61	-1.73
BNSC	0.00	-2.57	0.00	-4.00
BNEH	0.00	0.00	0.00	-2.05
BNSH	0.00	0.00	0.00	-0.32

1/ This column is not the marginal effect of Limerick 1 given acid rain. It is the cumulative effect of both Limerick 1 and acid rain.

SUPPLIED BY PHB

SO_2 O&M COSTS

50% reduction and elimination of two party purchases

Millions $

CONEMAUGH — INFLATION RATE 6.00% — 84/93 RATE 1.62

CAPACITY 1600 MW — HEAT RATE 9,690 BTU/KWH — SCRUB O&M 5.3 MILLS/KWH IN 1984$'S — MAX CAP PEN 4.0% — DISCNT RATE 9.70% — CAPITAL COSTS OF SCRUBBER RETROFIT 225 PER KW (1984$'S) — DIRECT EXPENDITURE 89.41%

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
TBTU													
	CONEMAUGH - TOTAL	74.65	74.19	74.63	79.09	73.07	73.15	80.41	73.18	73.57	80.17	72.73	71.42
20.72%	CONEMAUGH - PECO	15.47	15.37	15.46	16.39	15.14	15.16	16.66	15.16	15.24	16.61	15.07	14.80
GWH													
	CONEMAUGH - TOTAL	7703.82	7656.35	7701.96	8161.51	7540.87	7548.61	8298.04	7551.60	7592.05	8273.37	7505.47	7370.79
	CONEMAUGH - PECO	1596.23	1586.40	1595.85	1691.06	1562.47	1564.07	1719.35	1564.69	1573.07	1714.24	1555.13	1527.23
OPERATING	COST/KWH	8.58	9.09	9.64	10.22	10.83	11.48	12.17	12.90	13.67	14.49	15.36	16.29
MW $'S													
	CONEMAUGH - TOTAL	66.09	69.63	74.24	83.39	81.68	86.67	100.99	97.42	103.81	119.92	115.32	120.04
	CONEMAUGH - PECO	13.69	14.43	15.38	17.28	16.92	17.96	20.92	20.18	21.51	24.85	23.89	24.87

MW SCRUBBED WITH ACID RAIN	1993 MW	1993 % OF CAP	2000 MW	2000 % OF CAP
WITH LIN 1	114	7.1%	571	35.7%
WITHOUT LIN 1	243	15.2%	692	43.3%

SCRUB O&M COSTS ADJUSTED FOR CAPACITY PENALTY

TOT CONE.	WITH LIN 1	4.72	4.98	5.31	5.96	5.84	6.19	7.22	35.27	37.59	43.42	41.75	43.46
	166.56 PV	2.25	2.16	2.10	2.15	1.92	1.86	1.97	8.80	8.54	9.00	7.89	7.48
	WITHOUT LIN 1	10.10	10.66	11.34	12.74	12.48	13.24	15.43	42.87	45.69	52.78	50.75	52.83
	213.36 PV	4.82	4.62	4.49	4.60	4.11	3.97	4.22	10.69	10.39	10.94	9.59	9.10
	DELTA	5.38	5.66	6.04	6.78	6.64	7.05	8.22	7.61	8.10	9.36	9.00	9.37
48.80	PV	2.56	2.46	2.39	2.45	2.19	2.12	2.25	1.90	1.86	1.94	1.70	1.61
PECO	WITH LIN 1*	0.98	1.03	1.10	1.23	1.21	1.28	1.50	7.31	7.79	9.00	8.63	9.00
	34.10 PV	0.47	0.45	0.44	0.45	0.40	0.39	0.41	1.82	1.77	1.86	1.63	1.55
	WITHOUT LIN 1*	2.09	2.20	2.35	2.64	2.59	2.76	3.20	8.88	9.47	10.94	10.52	10.95
	44.21 PV	1.00	0.96	0.93	0.95	0.85	0.82	0.87	2.22	2.15	2.27	1.99	1.89
	DELTA	1.11	1.17	1.25	1.41	1.38	1.46	1.70	1.38	1.68	1.94	1.87	1.94
10.11	PV	0.53	0.51	0.50	0.31	0.45	0.44	0.47	0.39	0.38	0.40	0.35	0.33

	TOTAL MW'S RETROFITTED (INCREMENTAL) 1993	2000	PECO'S SHARE OF TOTAL MW'S RETROFITTED (INCREMENTAL) 1993	2000	TOTAL BOOK VALUE OF INVESTMENT 1993	2000	DIRECTS EXPENDITURE OF INVESTMENT 1993	2000
WITH LIN 1	114	457	24	95	8.60	54.12	7.69	48.39
WITHOUT LIN 1	243	449	50	93	18.34	53.18	16.40	47.54
DELTA	129	-8	27	-2	9.74	-0.95	8.70	-0.85

SUPPLIED BY P. H B.

SO_2 O&M costs
50% reduction elimination of two purchases
Millions $

OF SCRUBBER RETROFIT 225 PER KW (1984$'S)

DIRECT EXPENDITURE % ASSUMED 89.41%

999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
41	73.18	73.37	80.17	72.73	71.42	73.74	72.48	70.87	74.44	72.88	71.25	73.88	72.70	71.45	74.14
66	15.16	15.24	16.61	15.07	14.80	15.28	15.02	14.68	15.42	15.10	14.76	15.31	15.06	14.80	15.36
04	7551.60	7592.05	8273.37	7505.67	7370.79	7609.60	7479.67	7313.21	7681.94	7521.36	7353.15	7624.56	7502.48	7373.79	7651.50
35	1564.69	1573.07	1714.24	1555.13	1527.23	1576.71	1549.79	1515.30	1591.70	1558.43	1523.57	1579.81	1554.51	1527.85	1585.39
17	12.90	13.67	14.49	15.36	16.29	17.26	18.30	19.40	20.56	21.79	23.10	24.49	25.96	27.51	29.17
99	97.42	103.81	119.92	115.32	120.04	131.37	136.87	141.85	157.95	163.92	169.87	186.71	194.74	202.89	223.16
92	20.18	21.51	24.85	23.89	24.87	27.22	28.36	29.39	32.73	33.96	35.20	38.69	40.35	42.04	46.24
22	35.27	37.59	43.42	41.75	43.46	47.36	49.35	51.36	57.18	59.35	61.50	67.60	70.51	73.45	80.79
97	8.80	8.54	9.00	7.89	7.48	7.47	7.09	6.70	6.80	6.43	6.08	6.09	5.79	5.50	5.51
33	42.87	45.69	52.78	50.75	52.83	57.82	60.24	62.43	69.51	72.14	74.76	82.17	85.71	89.29	98.22
22	10.69	10.39	10.94	9.59	9.10	9.08	8.62	8.14	8.27	7.82	7.39	7.40	7.04	6.68	6.70
12	7.61	8.10	9.36	9.00	9.37	10.26	10.69	11.07	12.33	12.80	13.26	14.58	15.20	15.84	17.42
15	1.90	1.84	1.94	1.70	1.61	1.61	1.53	1.44	1.47	1.39	1.31	1.31	1.25	1.19	1.19
0	7.31	7.79	9.00	8.65	9.00	9.85	10.27	10.64	11.85	12.30	12.74	14.01	14.61	15.22	16.74
1	1.82	1.77	1.86	1.63	1.55	1.55	1.47	1.39	1.41	1.33	1.26	1.26	1.20	1.14	1.14
0	8.88	9.47	10.94	10.52	10.95	11.98	12.48	12.94	14.40	14.95	15.49	17.03	17.76	18.50	20.35
7	2.22	2.15	2.27	1.99	1.89	1.88	1.79	1.69	1.71	1.62	1.53	1.53	1.46	1.38	1.39
0	1.58	1.68	1.94	1.87	1.94	2.13	2.21	2.29	2.55	2.65	2.75	3.02	3.15	3.28	3.61
7	0.39	0.38	0.40	0.35	0.33	0.33	0.32	0.30	0.30	0.29	0.27	0.27	0.26	0.25	0.25

TOTAL BOOK VALUE OF INVESTMENT

1993	2000
8.60	54.12
18.34	53.18
9.74	-0.95

DIRECTS EXPENDITURES OF INVESTMENT

1993	2000
7.69	48.39
16.40	47.54
8.70	-0.85

Supplied by PHB

SO_2 O&M costs
50% reduction & elimination of 2 party purchases
Millions $

CONEMAUGH

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPACITY	1600										
HEAT RATE	9,690										
SCRUB O&M	5.3										
MAX CAP PEN	4.0%										
TBTU											
CONEMAUGH - TOTAL		72.88	71.42	73.90	72.53	71.45	74.33	72.78	71.08	73.90	72.68
20.72% CONEMAUGH - PECO		15.10	14.80	15.31	15.03	14.80	15.40	15.08	14.73	15.31	15.06
GWH											
CONEMAUGH - TOTAL		7521.36	7370.79	7626.11	7484.83	7373.79	7672.45	7510.32	7333.60	7626.11	7500.83
CONEMAUGH - PECO		1558.43	1527.23	1580.13	1550.86	1527.85	1589.73	1556.14	1519.94	1580.13	1554.17
OPERATING COST/KWH		30.92	32.77	34.74	36.82	39.03	41.37	43.85	46.49	49.27	52.23
MM $'S											
CONEMAUGH - TOTAL		232.53	241.55	264.91	275.60	287.80	317.43	329.36	341.00	375.78	391.78
CONEMAUGH - PECO		48.18	50.05	54.89	57.10	59.63	65.77	68.24	70.66	77.86	81.18
MW SCRUBBED											
WITH ACID RAIN											
WITH LIN 1											
WITHOUT LIN 1											
SCRUB O&M COSTS ADJUSTED FOR CAPACITY PENALTY											
TOT CONE. WITH LIN 1		84.19	87.45	95.91	99.78	104.20	114.92	119.24	123.46	136.05	141.84
164.56 PV		5.24	4.96	4.96	4.70	4.48	4.50	4.26	4.02	4.03	3.83
WITHOUT LIN 1		102.34	106.31	116.59	121.30	126.67	139.70	144.96	150.08	165.38	172.43
213.36 PV		6.37	6.03	6.03	5.72	5.44	5.47	5.17	4.88	4.91	4.66
DELTA		18.15	18.86	20.68	21.52	22.47	24.78	25.71	26.62	29.34	30.59
48.80 PV		1.13	1.07	1.07	1.01	0.97	0.97	0.92	0.87	0.87	0.83
PECO WITH LIN 1		17.44	18.12	19.87	20.67	21.59	23.81	24.71	25.58	28.19	29.39
34.10 PV		1.08	1.03	1.03	0.97	0.93	0.93	0.88	0.83	0.84	0.79
WITHOUT LIN 1		21.20	22.03	24.16	25.13	26.25	28.95	30.03	31.10	34.27	35.73
44.21 PV		1.32	1.25	1.25	1.18	1.13	1.13	1.07	1.01	1.02	0.97
DELTA		3.76	3.91	4.29	4.46	4.66	5.13	5.33	5.52	6.08	6.34
10.11 PV		0.23	0.22	0.22	0.21	0.20	0.20	0.19	0.18	0.18	0.17

RETROFITTED (INCREMENTAL)

WITH LIN 1
WITHOUT LIN 1

DELTA

SUPPLIED BY PHB