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R-943271 5/23/95
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Before the

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.*	)	Docket No. R-00943271
v.	)	
Pennsylvania Power & Light Company	)	

Surrebuttal
Testimony and Exhibit of
KENNETH EISDORFER

On Behalf of
University/College Coalition

May, 1995
Cook, Eisdorfer & Associates, Inc.

BA

PENNSYLVANIA POWER & LIGHT COMPANY

Before the

Pennsylvania Public Utilities Commission

Docket No. R-00943271

Surrebuttal Testimony of Kenneth Eisdorfer

Q. Please state your name and business address.

A. Kenneth Eisdorfer, 2258 Schuetz Road, St. Louis, Missouri, 63146.

Q. Are you the same Kenneth Eisdorfer who has previously testified in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to various points raised by PP&L rebuttal witnesses Kleha and Sipics. Each witness attempts to rebut my positions that: 1) PP&L's proposed monthly peak responsibility (12 CP) cost-of-service study is inappropriate for the Company's system and that 2) the winter peak (1 CP) cost-of-service study reflects PP&L's bulk power cost incurrence characteristics and should be utilized by the Commission for rate structure purposes. I will demonstrate that specific assertions made by these witnesses are either irrelevant or incorrect. Furthermore, I will show that when the deficient analyses which underlie these assertions are corrected, the results strongly support the adoption of the 1 CP methodology and the rejection of the 12 CP methodology.

The Assertions of Mr. Sipics
Relating to PP&L's Internal
Capacity Obligation to PJM

Q. Does Mr. Sipics agree with your position that PP&L's winter peaks are the overwhelming determinant of PP&L's Internal Capacity Obligation (ICO) to PJM?

A. No. He attempts to rebut my position by relying upon the following two assertions (page 19):

> "First, the PJM reserve requirement is calculated using 52 weekly peak load probability distributions; and
>
> Second, PP&L's ICO is increased slightly more by an increase in PP&L's summer peak than by a similar increase in PP&L's winter peak."

Q. Please react to Mr. Sipics' first assertion.

A. I do not dispute that the PJM reserve requirement is derived in the manner stated by Mr. Sipics. However, the fact is that neither the derivation methodology nor the magnitude of the reserve requirement have any relevance to my conclusion that PP&L's winter peaks are the overwhelming determinant of PP&L's ICO.

Q. Please explain.

A. To do so, we must briefly review how PP&L's ICO is computed. The ICO is equal to the product of the Diversified Planning Peak (DPPP) for PP&L multiplied by one plus the total reserve margin required by PJM.

With respect to the determination of PP&L's DPPP, there are three components. The <u>primary component</u> is the average of the <u>Company's winter peak loads</u> for the current PJM planning period and the previous period (reduced slightly for seasonal capability differences in installed capacity). The DPPP is obtained by applying a minor offset to the average winter peaks. This offset is obtained by adding together two diversity adjustments: 1) the Planning Period Adjustment (determined by using both PP&L's winter peak and summer peak) and 2) the Summer Peak Adjustment (which is based on PP&L's summer peak). As I stated in my direct testimony (page 8) this offset reduced PP&L's ICO by 6.9% for the 1994-1995 planning period from what it would have been otherwise. The figures in Table 1 show the components of PP&L's DPPP for the 1994-1995 planning period:

Table 1

Components of PP&L's Diversified Planning Peak
for the 1994-1995 Planning Period

	MW (1)	Percent of Total (2)
Average of PP&L's Winter Peaks	6,340	107.5%
<u>Diversity Adjustments</u>		
Planning Period Adjust.	(385)	(6.5)
Summer Peak Adjust.	(55)	(1.0)
Total	(440)	(7.5)
DPPP	5,900	100.0%

Note that the winter peaks component is 107.5% (6,340 MW) of the DPPP. The offset is equal to only 7.5% of the DPPP (440 MW).

The application of the reserve margin to the DPPP in the ICO computation has no impact upon the relative influence of the winter and summer peaks (the summer peaks are represented by the diversity adjustments offset) shown above for the DPPP. The clearest way to demonstrate this is to multiply the DPPP components shown in Table 1 by one plus the total reserve margin. The total reserve margin was (22.32% for the 1994-1995 planning period.) The resulting figures are effectively the components of PP&L's ICO and are shown in Table 2:

Table 2

Components of PP&L's ICO for
the 1994-1995 Planning Period

	MW (1)	Percent of Total (2)
Average of Winter Peaks	7,755	107.5%
Diversity Adjustments		
Planning Period Adjust.	(471)	(6.5)
Summer Peak Adjust.	(67)	(1.0)
Total	(538)	(7.5)
ICO	7,217	100.0%

Note: Column (1) is obtained by adjusting the DPPP figures shown in Column (1) of Table (1) for the total reserve margin of 22.32% (i.e., multiplying each figure by 1.2232.)

Note that the predominant influence of the winter peaks compared to the summer-related offset for the diversity adjustments is unchanged from Table 1. This is so because in deriving Table 2, each component was multiplied by a constant (i.e., one plus the reserve margin which is equal to 1.2232). Table 2 confirms that contrary to Mr. Sipics assertion, the reserve requirement is an irrelevant consideration in analyzing which of PP&L's peaks drive the magnitude of its ICO. PP&L's winter peaks are the overwhelming determinant of its ICO.

Q. Please now address Mr. Sipics' second assertion, specifically that PP&L's ICO is increased slightly more by an increase in PP&L's summer peak than by a similar increase in PP&L's winter peak.

A. This assertion is based upon two contentions. One contention (page 20) is that PP&L's load drop adjustment (which is a component of its total reserve margin) is "slightly higher for an increase in summer peak load than for an equal increase in winter peak load". I just discussed that the reserve margin is irrelevant to the relative influence of PP&L's winter and summer peaks in the ICO computation because it is effectively a multiplicative application of a constant to <u>each</u> component of the DPPP. However, putting that aside, as I noted in my direct testimony the load drop adjustment is very minor. Specifically, for the 1994-1995 planning period it increased PP&L's ICO by <u>0.15%</u> from what it would have been otherwise. This was equal to 9 MW out of a DPPP OF 5,900 MW. Suppose the load drop adjustment due to an increase in the summer peak relative to the winter peak increased "slightly" from 0.15% to 0.16% (a 6.7% increase). There would be no change in the megawatt value of the load drop adjustment (i.e., it would still be 9 megawatts). Even if relative summer load changes produced a huge increase in the load drop adjustment, its impact upon the ICO is deminimus. If it increased by one-third to 0.20%, the megawatt value for the 1994-1995 planning period would increase by only 3 megawatts, a negligible figure. Mr. Sipics' first contention should be ignored.

Q. What is Mr. Sipics' second contention?

A. Mr. Sipics represents (page 20) that "a specific increase in either the summer peak load or the winter peak load will produce a virtually identical increase in PP&L's DPPP." He then attempts to illustrate this through two examples. One example (Exhibit JFS-7, page 2) shows the impact upon PP&L's DPPP of a 100 megawatt increase in the Company's summer peak. The second example (Exhibit JFS-7, pge 3) is for a 100 megawatt increase in PP&L's winter peak.

Q. Is something seriously amiss with these examples?

A. Yes, very much so. Each example assumes that the load increase occurs in isolation. In other words, when one seasonal peak increases there is no change made to the other peak. I am unaware of a utility that can realistically have any expectation that when its summer peak increases, its winter peak will not change and vice-versa. Generally, changes in a utility's winter peak are accompanied by changes in its summer peak. This is certainly true for PP&L. Between 1990 and 1994, PP&L's winter peaks and summer peaks increased, on average, at the same annual rate (3.3%). Mr. Sipics' assumption of isolated load growth is simply not applicable to real-world utilities.

Q. Can you present an example that is representative of the real world which shows the impact upon PP&L's DPPP of increases in winter peaks and summer peaks?

A. Yes. The figures that appear on Schedule 1 of Exhibit KE-2 ( ) show the impact upon PP&L's DPPP which would result from 100 megawatt increases in <u>both</u> PP&L's winter peak and summer peak loads. As shown in Column 3 of page 1, the DPPP would increase by 99 megawatts. The components of this increase are:

Table 3

	DPPP Increase (MW)
	(1)
Average of PP&L's Winter Peaks	100
<u>Diversity Adjustments</u>	
Planning Period Adjust.	0
Summer Peak Adjust.	(1)
Total	(1)
Total DPPP Increase	99

Once again we see the overwhelming influence of PP&L's winter peak loads upon its ICO. This clearly supports the use of the winter peak cost-of-service study and the rejection of the 12 CP method for evaluating customer cost causation.

The Assertion of
Mr. Kleha Relating
to Scheduled Maintenance

Q. What is Mr. Kleha's assertion with respect to the impact of scheduled maintenance upon PP&L's capacity requirements?

A. Mr. Kleha asserts (pages 6-7) that if one adds PP&L's monthly peak load to its scheduled maintenance requirement, "PP&L's maximum capacity requirements do not always occur in the three-month winter period (December, January and February)."

Q. Have you ever before seen a utility analyst add together monthly peak load megawatts and scheduled maintenance megawatts?

A. No.

Q. What is the fallacy of such an addition?

A. It implicitly equates the impact upon cost causation of peak loads with scheduled maintenance. This is incorrect. The timing of scheduled maintenance is a function of the load characteristics of a utility. A utility schedules the bulk of its scheduled maintenance during months when there is no risk that weather extremes will create a capacity shortage problem. During 1992-1994, more than two-thirds of PP&L's aggregate capacity removed from service for scheduled maintenance occurred during the relatively weather-quiescent months of March, April, May, ~~September~~ and October and November. As I stated in my direct testimony, these are among the months that have never contained the annual system peak and have virtually no chance to do so in the future. PP&L is simply responding in a prudent fashion to its load characteristics by scheduling most of its maintenance during these months. This scheduling has no impact upon PP&L's cost causation for production plant which is driven by its annual system peak which occurs invariably during the winter.

Q. Even if one were to accept the concept of adding together monthly peak loads and schedule maintenance capacity figures, what are the results for PP&L?

A. Mr. Kleha purports to show (page 7) the resulting "maximum capacity requirement" months for 1989-1994. His results for at least the 1992-1994 period appear to be largely incorrect. The figures that appear on Schedule 2 of Exhibit KE-2 ( ) show the summation of monthly system peaks and scheduled maintenance megawatts for these three years. These figures were taken directly from PP&L's response to OCA Interrogatory, Set III, Question 28 (which shows data for 1992-1994 only). The "maximum capacity requirement" months shown by Mr. Kleha as compared to the results of Schedule 2 are:

Year	Mr. Kleha	Schedule 2
1992	March	February
1993	March, April, November	February, March, December
1994	March, April, November	January, ~~February~~, March, April

Therefore, contrary to Mr. Kleha's rebuttal testimony, which represents that the "maximum capacity requirement" occurs strictly during spring or fall months, a correct analysis reveals that it has recently occurred predominantly during the winter period. This is so because of the overwhelming magnitude of PP&L's winter peak loads.

Q. Do you have a concluding comment?

A. Yes. The Commission should not allow itself to be swayed by the Company's fictions about PP&L's capacity responsibility to PJM and its scheduled maintenance in rendering a decision about an appropriate cost-of-service study methodology. In my opinion, an accurate analysis of the PP&L system provides overwhelming support for the winter peak cost allocation method and absolutely no support for PP&L's 12 CP method.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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Derivation of PP&L's Diversified Planning Peak for PJM's 1994-1995 Planning Period
-Actual vs. 100 Megawatt Increases in Both Summer & Winter Peak Loads

			100 MW Increase in Both Winter & Summer Peak Loads	
Line	Description	Actual (MW) (1)	Amount (MW) (2)	Change (MW) (3)
	Reduced* Winter Peaks			
1	This Planning Period	6,419	6,519	100
2	Last Planning Period	6,260	6,360	100
3	Average of Lines 1 and 2	6,340	6,440	100
	Diversity Adjustments (Page 2)			
4	Planning Period Adjustment	385	385	0
5	Summer Peak Adjustment	55	56	1
6	Total	440	441	1
7	Diversified Planning Peak (Line 3-Line 6)	5,900	5,999	99

*Reduced for the difference between winter and summer installed capacity.

Source for Column 1: PP&L's response to Interrogatory OTS-RB-28D.

PENNSYLVANIA POWER & LIGHT COMPANY

Derivation of 1994-1995 Planning Period Diversity Adjustments for PP&L
-Actual vs. 100 Megawatt Increases in Both Summer & Winter Peaks Loads

Line	Description	Actual (MW) (1)	100 MW Increase in Both Winter & Summer Peak Loads: Amount (MW) (2)	Change (MW) (3)
	Derivation of Planning Period Diversity Adjustment			
1	Average of Reduced* Winter Peaks (From page 1, line 3)	6,340	6,440	100
2	Forecasted Summer Peak	5,570	5,670	100
3	Difference (Line 1-Line 2)	770	770	0
4	Planning Period Diversity Adjustment (One-half of Line 3)	385	385	0
	Derivation of Summer Peak Diversity Adjustment			
5	Forecasted Summer Peak	5,570	5,670	100
6	Total Forecasted Summer Peaks	46,669	46,769	100
7	Line 5 as a Percentage of Line	11.9%	12.1%	
8	Total PJM Summer Peak Diversity Adjustment	462	462	
9	PP&L's Summer Peak Diversity Adjustment (Line 7 Percentages applied to Line 8)	55	56	1

*Reduced for the difference between winter and summer installed capacity.

Source for Column 1: PP&L's response to Interrogatory OTS-RB-28D.

PENNSYLVANIA POWER & LIGHT COMPANY

Monthly System Peaks and Scheduled Maintenance (Megawatts)

Line	Month	System Peak (1)	Scheduled Maintenance (2)	"Maximum Capacity Requirement" (1)+(2) (3)
	1994			
1	January	6,403	950	7,353
2	February	6,193	163	6,356
3	March	5,681	829	6,510
4	April	4,742	1,849	6,591
5	May	4,404	1,763	6,167
6	June	5,521	644	6,165
7	July	5,638	128	5,766
8	August	5,329	128	5,457
9	September	4,477	780	5,257
10	October	4,661	652	5,313
11	November	5,083	1,364	6,447
12	December	5,646	728	6,374
	1993			
1	January	5,507	77	5,584
2	February	6,130	77	6,207
3	March	5,826	1,477	7,303
4	April	4,685	1,477	6,162
5	May	4,443	706	5,149
6	June	4,947	317	5,264
7	July	5,409	61	5,470
8	August	5,388	61	5,449
9	September	5,241	61	5,302
10	October	4,639	803	5,442
11	November	5,064	1,072	6,136
12	December	6,001	787	6,788

Source: PP&L's Response to OCA Interrogatory, Set III, Question 28.

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Monthly System Peaks and Scheduled Maintenance (con't)
(Megawatts)

Line	Month	System Peak (1)	Scheduled Maintenance (2)	"Maximum Capacity Requirement" (1)+(2) (3)
	1992			
1	January	5,974	61	6,035
2	February	5,706	727	6,433
3	March	5,345	846	6,191
4	April	4,795	846	5,641
5	May	4,183	1,114	5,297
6	June	4,567	327	4,894
7	July	5,104	346	5,450
8	August	5,029	426	5,455
9	September	4,797	426	5,223
10	October	4,756	936	5,692
11	November	4,930	644	5,574
12	December	5,490	644	6,134

Source: PP&L's Response to OCA Interrogatory, Set III, Question 28.

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x Ex DSH-3

Statement 4-R R-943271 Hbg
5/23/95

Rebuttal Testimony of Donald S. Hoch

Docket No. R-00943271

Q. Please state your full name and business address.

A. Donald S. Hoch, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. Have you testified previously in this proceeding?

A. Yes, I submitted PP&L Statement No. 4 and the accompanying PP&L Exhibit Nos. DSH-1 and DSH-2. I was cross-examined with respect to my direct testimony at the hearing held on March 21, 1995.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the direct testimony of witnesses on behalf of the Office of Trial Staff ("OTS"), Office of Consumer Advocate ("OCA"), and PP&L Industrial Customer Alliance ("PPLICA") regarding their proposed adjustments to the Company's following expense claims:

1. Levelizing Susquehanna Steam Electric Station ("Susquehanna") modified sinking fund ("MSF") depreciation expense;
2. Amortization accounting for certain General Property accounts;
3. Decommissioning expense for fossil generating plants; and
4. Lives used for depreciation purposes for Holtwood 17, Martins Creek 1 and 2 and Sunbury 1, 2, 3 and 4 (the "older fossil units").

Levelized MSF Depreciation Expense

Q. Which opposing party witnesses have taken issue with the Company's proposal to levelize the MSF depreciation expense for Susquehanna?

A. The Company's proposal has been disputed by Mr. Joseph J. Sivulich, on behalf of the OTS, Dr. Charles E. Johnson, on behalf of the OCA, and Mr. Lane Kollen, on behalf of PPLICA.

Q. Please address the reasons advanced by OTS witness Sivulich for his proposal to reject levelized MSF depreciation expense.

A. Mr. Sivulich listed four points that he believes support his recommendation (OTS Statement 2, pp. 32-33). Two of those points (numbers 1 and 3 in Mr. Sivulich's list), are essentially the same; namely that continuing the MSF method will result in a lower revenue requirement "in the present case." While those statements are accurate as far as they go, they hardly provide a definitive rationale for rejecting the Company's proposal. The ultimate decision to approve or reject the Company's proposal for levelizing MSF depreciation should be based on the substance and the merits of that proposal, including whether it results in fair treatment of the Company and its customers in light of all of the facts. Indeed, if Mr. Sivulich's contentions were accepted at face value as the appropriate way to assess depreciation methods, then the MSF method would be used for <u>all</u> utility property. However, straight-line depreciation is the method consistently used by utilities and approved by the Commission.

Additionally, those statements ignore the future consequences of a short-sighted rate-minimization approach. Continuing MSF depreciation on its current basis would produce a "lower revenue requirement" in this case only because that method results in increasing levels of depreciation expense over the four-year period ending in 1999. Specifically, this component of PP&L's total depreciation expense would increase from approximately $142 million in 1995 to $194 million in 1998. Consequently, the same factor that Mr. Sivulich relies upon to justify his contention that MSF depreciation produces "a lower revenue requirement...in the present case" undercuts his fourth point, that "continuing the present MSF until 1999 will not prevent the company from recovering all of the depreciation expense that it is entitled to." Because the "present MSF" method requires increases in depreciation each year until 1999, the Company could not be assured of recovering all of the depreciation expense that "it is entitled to" unless it made annual rate filings that reflect those annual depreciation changes as well as all other factors impacting its revenue requirement. Although there are a number of considerations affecting the decision whether to file a base rate increase request, rejection of the proposal to levelize MSF depreciation could only result in an additional factor driving the need for rate filings during the period through 1998.

Finally, Mr. Sivulich's point that the proposed levelizing of MSF depreciation "is not mandated by the Financial Accounting Standards Board" is no reason to reject the Company's proposal. Although the Commission, in setting rates, clearly should consider what the Financial Accounting Standards Board ("FASB") mandates, most of the issues raised in rate proceedings are not the subject of any FASB mandate or discussion. Consequently, as with those kinds of issues, the Company's levelization proposal should be analyzed on its own merits.

Q. Please address the reasons advanced by OCA witness Johnson and PPLICA witness Kollen for rejecting the Company's proposal to levelize MSF depreciation.

A. Dr. Johnson and Mr. Kollen have expressed a common theme, that the Company's proposal to levelize MSF depreciation ignores the effect on rate base and return that would result, prospectively, from such a depreciation change. Specifically, both contend that MSF inherently levelizes <u>all</u> after-tax fixed costs (depreciation and return) because increases in MSF depreciation from year to year would be fully offset by corresponding decreases in required return. Dr. Johnson and Mr. Kollen assume that year-to-year reductions in required return will occur because of declining rate base caused by the increase in <u>accrued</u> depreciation. In short, they contend that accrued depreciation is a source of so-called "negative attrition."

Q. What are the defects in that argument?

A. The argument has a number of flaws. However, it's principal defect is that it assumes a static analysis of rate base. Their argument could be correct <u>only</u> if one assumes that the Company will not make any <u>new</u> investment in plant after rates are put into effect. Obviously, that is a totally unrealistic assumption. The Company's annual investment in new plant will in all likelihood exceed the reductions in rate base attributable to accrued depreciation. As a consequence, <u>growth</u> in PP&L's rate base is a source of attrition and, therefore, would drive the need for future rate filings. Rejecting the Company's proposal to levelize MSF depreciation would only contribute to attrition, accelerate the need for future rate filing and potentially increase the frequency of such filings.

Q. Mr. Kollen also asserts that the Company's proposed levelization is an attempt "to reach beyond the end of the test year for a projected cost increase" and, therefore, violates the test year concept. Please address this contention.

A. Mr. Kollen is entirely incorrect. Additionally, as I will explain, the "negative attrition" argument that he and Dr. Johnson rely upon actually represents exactly the kind of attempt to anticipate post-future test year events that Mr. Kollen has criticized.

The Company has proposed recovering in equal annual installments -- that is, on a straight-line basis -- the same amount of total depreciation it would recover under MSF between September 30, 1995 and December 31, 1998 for pre-1989 vintage Susquehanna property. In view of the fact that PP&L employs a straight-line method to depreciate all the rest of its plant-in service, it's proposal to levelize Susquehanna MSF depreciation through 1998 could hardly be regarded as an inappropriate deviation from standard depreciation practice that attempts to "reach beyond the end of the test year," as Mr. Kollen asserts.

As previously noted, Mr. Kollen and Dr. Johnson, however, have used a post-future test year analysis to support their argument that MSF depreciation levelizes total after-tax fixed costs. In essence, they have tried to project future accrued depreciation balances and argue that, in anticipation of future increases in accrued depreciation which they assume will reduce rate base, the lower depreciation expense produced by MSF in this case is fully justified. This kind of post-future test year projection is not appropriate. But, if such a projection were to be made then, as I have previously explained, post-future test year plant additions should also be considered.

Finally, the test year concept assumes that the relative relationship of various rate base components will remain about the same from year-to-year. Thus, for example, while accrued depreciation may increase, other changes -- such as additional investment -- will offset that reductive effect on rate base.

In short, a kind of dynamic stability among rate base components is assumed. Significantly, the straight-line method, which is designed to recover depreciation at a levelized annual rate, is the depreciation method virtually universally applied for ratemaking purposes in Pennsylvania. Clearly, if there were any inconsistency between the use of levelized depreciation and the test year concept, that universal acceptance of straight-line depreciation would not have occurred.

Q. Mr. Kollen has also characterized the Company's proposal as an "acceleration of the depreciation recovery" and as "prematurely collecting" depreciation from customers. Is that characterization accurate?

A. No, it is not. For the reasons fully explained in my direct testimony (PP&L Statement 4, pp. 10-13), a significant portion of the depreciation to be recovered during the period from September 30, 1995 to December 31, 1998 consists of depreciation that would have been recovered well before now if straight-line depreciation rather than MSF had been used since Susquehanna Units 1 and 2 were included in rate base. What Mr. Kollen refers to as an "acceleration" in fact relates to depreciation the recovery of which was <u>deferred</u> from prior years, under the operation of the MSF method.

Q. Earlier you indicated that MSF depreciation would increase from $142 million in 1995 to $194 million in 1998. Describe the level of increase that occurred prior to 1995.

A. In the Company's last base rate case, at Docket No. R-842651, its claim for MSF depreciation was $35.5 million. Each year thereafter PP&L booked depreciation using the MSF method, which increased in amount over the prior year. Between 1985 and 1995 PP&L will have booked approximately $324 million in MSF deprecation above the $35.5 million annual accrual on which its existing base rates were established.

Q. Dr. Johnson has prepared Schedule 2 to OCA Exhibit CEJ-2 which purports to compare depreciation and return under MSF and the Company's levelization proposal. Have you reviewed that Schedule?

A. I have reviewed Schedule 2 to OCA Exhibit CEJ-2. It contains errors that have a significant impact on the "Total Capital Recovery" amounts shown on that Schedule, as outlined below:

- The figures for "Plant in Service" and "Depreciation Reserve" are over-stated because they include Susquehanna property placed in service after December 31, 1988, which is not being depreciated under the MSF method.
- The Company has proposed to levelize MSF depreciation for a 39-month period (September 30, 1995 to December 31, 1998). Dr.

Johnson has erroneously imputed the levelized depreciation amount for a 48-month period (August 31, 1994 to September 30, 1998). Consequently, he has overstated the levelized depreciation expense.

- Dr. Johnson's calculation is based on annual intervals beginning on September 1, 1994 and ending on September 30, 1998. However, the MSF depreciation accruals he employed are for calendar year periods.

Q. Have you prepared a comparable schedule using corrected data as inputs?

A. Yes, I have prepared comparable calculations, which are provided as PP&L Exhibit DSH-3. The exhibit is done on a calendar year basis, which corresponds to the MSF depreciation accruals. This exhibit shows that "Total Capital Recovery" for the entire four-year period ending December 31, 1998 is $5 million less under the Company's levelized proposal. Dr. Johnson's flawed calculation showed "Total Capital Recovery" under the Company's proposal to be about $12 million more. Additionally, the net present value of the revenue streams represented by the figures in the columns captioned "Total Capital Recovered" are the same under the MSF method and the Company's proposal. Although I do not believe that Dr. Johnson's approach, which he tried to illustrate using Schedule 2 to OCA Exhibit CEJ-2, provides any basis or justification for his recommendations to reject the Company's levelization proposal, it is worthwhile to correct the errors in his calculation.

Amortization Accounting -- General Property Accounts

Q. Which opposing party witnesses have addressed the Company's claim for the use of amortization accounting for certain property accounts?

A. Only Dr. Johnson, on behalf of the OCA, has addressed this claim. Although Dr. Johnson does not challenge the Company's proposal to employ amortization accounting, he disagrees with the amortization periods PP&L has proposed for most of the affected accounts. As you might expect, he proposed longer amortization periods, which would reduce the Company's amortization expense claim by $3.14 million (OCA Exhibit CEJ-2, Schedule 2, p. 1 and Schedule 3, p. 2).

Q. What does Dr. Johnson contend is the basis for the longer amortization periods he proposes?

A. It is not clear from a review of OCA Exhibit CEJ-2, Schedule 2 what the basis is for his recommendation. In general, Dr. Johnson claims to have relied upon the so-called "Current Lives," which represent the service lives used to establish annual depreciation accruals reflected in the Company's existing base rates for all accounts except Account 391.6, General Computers. Those lives were based on a service life study performed in 1980 (the "1980 study"). Account 391.6, which includes the Company's investment in hand-held computers for automated meter reading, was established in 1986, and the "current life" used for book depreciation is five years, not 20 years as Mr. Johnson erroneously assumed.

While Dr. Johnson claims to rely upon the results of the 1980 study, his recommendations differ in several respects, presumably reflecting his judgment that a 15-year old study is not particularly relevant to determining appropriate current amortization periods. Dr. Johnson also refers to a retirement rate analysis that I prepared in 1994. This analysis applied actuarial techniques to calculate so-called "best fit" survivor curves. Mathematically determined survivor curves, while important, are but one input into the determination of appropriate service lives, as I will explain at a later point. Although Dr. Johnson refers to the results of the 1994 retirement rate analysis from time-to-time to support the amortization periods he proposes, in several significant respects he has departed drastically from the results of that study as well. For example, the 1994 retirement rate analysis indicated a "best fit" survivor curve for Account 395, Laboratory Equipment, based on an average service life of 19.2 years. Inexplicably, Dr. Johnson proposes a <u>40-year</u> amortization period for that account. The Company has claimed a 15-year amortization period for Laboratory Equipment. Similarly, for General Computers, the 1994 retirement rate analysis indicated a "best fit" survivor curve based on an average service life of 8.5 years. As previously indicated, the "current life" for that account is five years. Nonetheless, Dr. Johnson accepted a ten-year amortization period.

In summary, Dr. Johnson has proposed amortization periods that lack rational, consistent or understandable support. To the extent he has tried to offer support for his recommendations, it consists of indiscriminate use of stale or incomplete data. Moreover, while claiming to rely on prior Company studies and analyses, Dr. Johnson has, without explanation, departed from their indications to adopt different -- and for the most part longer -- amortization periods.

Q. Are the results of the 1980 study relevant to a determination of appropriate current amortization periods?

A. No. The Company's investment in the affected accounts has changed and additional retirements and exposures have occurred. As a general rule, a service life study that is over five years old is typically considered outdated for determining annual depreciation accruals for ratemaking purposes.

Q. You earlier referred to the 1994 retirement rate analysis you performed. Do its results constitute a service life study?

A. No, they do not. An historical actuarial analysis is but one item on which a depreciation analyst relies to make engineering judgments about future life characteristics. A well-informed analyst will also examine other contributing factors and conditions that cause future life characteristics to differ from purely historical indications. These are precisely the kinds of factors that I explicitly considered in developing the amortization periods proposed for the General Property Accounts. Moreover, I provided detailed documentation concerning these factors to the OCA. Dr. Johnson unfairly characterizes my review as "discussions" with PP&L personnel about "how long furniture should last." In fact, a determination of management's philosophy of property utilization and property replacement is an essential aspect of service life determination, and I know of no depreciation expert that would disregard such inputs.

Q. Is there any other evidence that would indicate Dr. Johnson does not understand or has misconstrued fundamental depreciation concepts?

A. Yes, there is. At page 14 (lines 21-24) of his direct testimony (OCA Statement 5), Dr. Johnson attempts to demonstrate that the Company's proposed amortization period would greatly accelerate its capital recovery for Account 391.2, Furniture. To that end, he divided the unrecovered net plant investment by the Company's requested amortization accrual and, based on the result, concludes that the amortization period is five years, not 20 years as the Company has claimed. Unfortunately, what he fails to understand is that the unrecovered net plant does not represent <u>new</u> investment, for which a full 20-year recovery period would be appropriate. Rather, based on the average attained age of the Company's unrecovered investment in that Account, which would approximate 15 years, the remaining recovery period is approximately five years. Additionally, Dr. Johnson fails even to consider the age distribution of the property in Account 391.2; the possible changes in depreciation parameters over time; and other factors that would directly affect the reserve balance for this Account.

Fossil Decommissioning

Q. Which opposing party witnesses have addressed the Company's claim for fossil plant decommissioning expense?

A. OTS witness Sivulich, OCA witness Catlin and PPLICA witness Kollen have all addressed the issue. Mr. Thomas LaGuardia will also address this issue on behalf of the Company and will respond to the testimony of these witnesses.

Q. On what bases do Mr. Sivulich and Mr. Catlin oppose the Company's fossil decommissioning claim?

A. These witnesses contend that, because fossil decommissioning is related to "routine" future retirement projects, which do not pose safety or health threats like those created by nuclear power plants, the associated costs should be recovered through an after-the-fact net salvage amortization following actual retirement. In addition, they contend that because all of the elements of decommissioning costs are not known with exactitude, recovery of those costs at this point is not appropriate.

Q. Would the retirement of existing fossil generating stations be "routine," as Mr. Sivulich contends?

A. No. For example, the decommissioning of two 740 megawatt units at Montour Steam Electric Station at an estimated cost of approximately $135 million (at 1994 price levels) could hardly be characterized as a "routine" retirement. The complex and extraordinary efforts that will be required to decommission an existing fossil plant upon its retirement are described in detail in Mr. LaGuardia's direct and rebuttal testimony.

It should be noted that, in the last 23 years, PP&L has decommissioned only one unit, which was a 29 megawatt combustion turbine (see PP&L Response to OCA Interrogatory Set IV, No. 87). The units decommissioned prior to that were all relatively small. None of those units had top-hung or supercritical boilers. Moreover, prior fossil-steam decommissionings occurred before implementation of the stringent environmental regulations in effect today.

Q. Is fossil decommissioning free from safety or health hazards as Mr. Sivulich and Mr. Catlin contend?

A. Not at all. Most fossil fueled plants in service today contain extensive amounts of asbestos, harmful chemicals and other materials that pose safety and health risks to workers, to the environment and potentially to the public at large. Although different in nature, these risks and hazards involve just as much concern about public health and safety as radioactivity or the non-radiologic components of nuclear plants, as Mr. LaGuardia has explained. Because of these risks and hazards, the dismantling of fossil plants is heavily regulated by the U.S. Environmental Protection Agency and the Pennsylvania Department of Environmental Resources, among others.

Q. Are there affirmative reasons, from a ratemaking perspective, that the Company's proposed treatment of decommissioning costs is superior to the after-the-fact amortization of net salvage?

A. Yes. Given their magnitude, it is more appropriate to recover fossil decommissioning costs from customers who are actually receiving service from the generating facilities that give rise to such costs. The net salvage amortization approach would defer those costs and impose them on an entirely new generation of customers. Along these lines, the Company's proposal is consistent with the ratemaking treatment accorded net salvage in most other jurisdictions, where it is reflected on a prospective basis as an element of the annual accrual rate.

Q. Please address the contentions by Messrs. Sivulich, Catlin and Kollen that decommissioning costs are "speculative" and, therefore, should not be recovered until actually expended.

A. Simply because the costs and the potential accrual period are not known with exactitude is no reason to ignore the fact that costs will be incurred and they will be substantial. The fossil decommissioning study prepared by Mr. LaGuardia contains a detailed analysis based on the best available information. While opposing party witnesses have made blanket statements that assumptions used by Mr. LaGuardia are "speculative," none of them has offered any specific criticism or indicated how he believes the assumptions should be changed.

Additionally, Mr. Kollen's reliance on OCA Exhibit LK-2 is misplaced. Mr. Kollen has used Exhibit LK-2 to try to compare the Company's estimate for decommissioning of existing fossil plants to its previously incurred decommissioning costs. However, as I have discussed, such comparisons are meaningless given the small size of those units (all but one were under 50 MW), when the retirements occurred (most were in the 1950s, and only one occurred after 1972) and the substantial environmental, safety and health risks that have been identified in the interim.

<u>Lives of Older Fossil Plants</u>

Q. Please address Mr. Kollen's testimony concerning the Company's proposal to change the depreciable lives of the older fossil units.

A. Mr. Kollen states that the Company has included an additional $20.476 million in its cost of service, on a total Company basis, and $16.687 million on a jurisdictional basis, due to its proposal to reduce the lives of the older fossil units. Those figures are not correct. Mr. Kollen simply calculated the difference between the Company's claimed annual depreciation for these units compared to what the Company had budgeted for the future test year ending September 30, 1995. The budgeted value used by Mr. Kollen is not an appropriate basis for comparison because it was not annualized and did not include changes to interim retirement curves that would be appropriate irrespective of whether the Company's proposed life spans are approved. If the Company's claim for shortening the depreciable lives were not adopted, then the effect on its annual depreciation expense would be $18.089 million on a total Company basis.

Q. Do you have any other comments regarding Mr. Kollen's testimony on the subject of the depreciable lives of the older fossil units?

A. Yes, I do. On page 13 (lines 18-22) of his direct testimony, Mr. Kollen implies that the <u>only</u> valid deactivation date is one which represents the actual retirement date of a plant. If that were the case, then I question what date one would use when a plant is initially placed in-service. At that point in time, there is only a best estimate of how long the plant will be expected to last. If one were to assume that, through continual maintenance, a utility would be able to keep the plant operating indefinitely (an assumption Mr. Sivulich improperly makes), then the depreciable life would be indefinite, and depreciation expense would be zero! Obviously, this is not reasonable. At any point in time, the best available data should be used in determining the deactivation dates for fossil-fueled plants. By deferring a decision into the future until a precise deactivation date is known, as Mr. Kollen suggests, the Company would simply be deferring the opportunity to allocate incremental depreciation expense over a greater number of years and, thereby, penalizing those customers that would be on its system when deactivation of a unit approaches. Appropriate matching of benefits from the unit with its costs would be lost.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Exhibit DSH-3

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit to Accompany

the Rebuttal Testimony

of

Donald S. Hoch

Concerning

Susquehanna Depreciation

DSH Modified Sinking Fund -- Calendar Year Basis

Year Ending	Plant in Service	Depreciation Reserve	Net Plant	Return at 10.17%	Depreciation Accrual	Total Capital Recovery	NPV
12/31/95	3,745	837	2,908	296	142	438	
12/31/96	3,745	994	2,751	280	157	437	
12/31/97	3,745	1,169	2,576	262	175	437	
12/31/98	3,745	1,363	2,382	242	194	436	
					668	1,748	1,380

DSH Levelized Approach -- Calendar Year Basis

Year Ending	Plant in Service	Depreciation Reserve	Net Plant	Return at 10.17%	Depreciation Accrual	Total Capital Recovery	NPV
12/31/95	3,745	845	2,900	295	150	445	
12/31/96	3,745	1,018	2,727	277	173	450	
12/31/97	3,745	1,191	2,554	260	173	433	
12/31/98	3,745	1,364	2,381	242	173	415	
					669	1,743	1,380

DOCUMENT FOLDER

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 5-R R-943271 5/23/95

Rebuttal Testimony of Douglas A. Krall JK Hbg

Docket No. R-00943271

REBUTTAL TESTIMONY OF DOUGLAS A. KRALL
DOCKET NO. R-00943271

Q. Please state your name and business address.

A. Douglas A. Krall. Two North Ninth St., Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") Manager-Integrated Resource Planning.

Q. Have you testified previously in this proceeding?

A. Yes. I submitted written direct testimony on December 30, 1994 (PP&L Statement 5), and I was cross-examined at a hearing held on March 21, 1995.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the opposition raised by several witnesses to PP&L's proposal to shorten the depreciation lives of the generating units designated as Holtwood 17, Martins Creek 1 & 2, and Sunbury 1, 2, 3, & 4. The witnesses who have expressed opposition and whose testimony I will be addressing are as follows:

1. Thomas J. Prisco testifying on behalf of the Department of Defense and the Federal Executive Agencies (DOD Statement No. 1);

2. Joseph J. Sivulich testifying on behalf of the Office of Trial Staff (OTS Statement No. 2);

3. Dr. Charles E. Johnson testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA Statement No. 5); and

4. Lane Kollen testifying on behalf of the PP&L Industrial Customer Alliance (PPLICA Statement No. 9).

Q. Please summarize PP&L's proposal regarding the depreciation lives of Holtwood 17, Martins Creek 1 & 2, and Sunbury 1, 2, 3, & 4.

A. As I have stated in direct testimony, PP&L is proposing to shorten the remaining depreciation lives of these units by amounts that vary from six to twelve years and result in a common date of 2003 for the purpose of calculating depreciation for all of these units. This proposal is based on the following factors:

1. The in-service dates of these units range from 1949 to 1954 making them currently between 40 and 45 years old. Given that power plant equipment of that vintage was typically designed for 30 to 40 years of operation, it is not surprising that significant equipment replacement needs are being identified.

2. These relatively old power plants operate at lower temperatures and without some of the design features of newer plants and, consequently, produce electricity less efficiently than newer plants.

3. A significant number of environmental issues are expected to affect power plants in general and coal-fired power plants in particular around the Year 2003. The Company's specific concerns are for NOx reduction

requirements expected to be defined in order to achieve ozone attainment in the Northeast under Title I of the 1990 Clean Air Act Amendments, and reductions in emissions of air toxics which may be required under Title III of the 1990 Amendments. Compliance with these requirements will require the installation of two different control systems.

4. These generating units are individually relatively small (net generator ratings are between 73 MW and 150 MW) meaning there are few economies of scale to make equipment replacements and environmental retrofits less economically burdensome.

It is our judgment that the combination of these factors makes the continued operation of these units beyond this time frame less certain than it was thought to be in 1988 when the current deactivation dates were established.

Q. What arguments do the witnesses you have listed offer in support of their common position that the existing deactivation dates be retained?

A. There are four themes that are generally common to these witnesses. These themes are as follows:

1. The proposal to shorten the depreciation lives of these units is only for the purpose of increasing revenue requirements in this proceeding.

2. The Company has performed no studies which support the shorter lives. The studies which have been performed conclude that continued operation is the appropriate course.

3. Future environmental compliance costs are too speculative to consider as a threat to continued operation.

4. The Company does not show retirement of these units in its capacity plans.

Q. How does the Company respond to the first argument – that the proposal to shorten the depreciation lives of these units is only for the purpose of increasing revenue requirements in this proceeding?

A. At the outset, PP&L objects strenuously to the suggestion that we have arbitrarily advanced these dates simply for the purpose of demonstrating an increased revenue requirement. As should be apparent from the record, PP&L has a sound and rational basis for proposing the shortened lives.

Furthermore, PP&L believes that shortening these lives at this time in light of the threats described is consistent with the concept that current customers should bear prudent costs incurred on their behalf. To ignore these issues at this time would put future customers unnecessarily at risk of having to bear costs for investment which may not provide them service. In this regard, it is important to put this proposal in a broader context. In PP&L's last base rate proceeding (1985), the deactivation dates for the purpose of calculating depreciation for these plants were as follows:

Holtwood 17	1994
Martins Creek 1 & 2	1995
Sunbury 1, 2, 3 & 4	2000.

In 1988, PP&L proposed and the Commission accepted life extensions which arrived at the current dates, namely:

Holtwood 17	2009
Martins Creek 1 & 2	2015
Sunbury 1, 2, 3 & 4	2010.

At the time of those revisions, the Company anticipated that Acid Rain legislation would likely require reductions in NOx and SO2 emissions, although the final form of those requirements was, at that time, uncertain. Those requirements, which became Title IV of the 1990 Clean Air Act Amendments, were factored into the extended dates. The Company did not anticipate the need for region-wide NOx reductions to achieve ozone attainment outside of its service territory (Title I) and it did not anticipate scrutiny on emissions of trace toxics (Title III). Absent these insights, the Company passed on to customers the benefits of lower depreciation levels. Had the Company the information in 1988 that it has now, it may well have only proposed extensions to 2003 in each case. The Company asserts that those dates would probably have been accepted at that time with little or no opposition, and that the only reason there is a question now is because dates which were, in hindsight, overly extended must now be advanced to arrive at the same point.

Q. How does the Company respond to the second argument -- that there are no studies which support the shorter lives?

A. The Company does not agree with the assertion that there are no studies or analytical support for the proposal to shorten the depreciation lives of Holtwood 17, Martins Creek 1 & 2, and Sunbury 1, 2, 3 & 4. As I will describe, the Company has provided appropriate analytical support in response to interrogatories submitted by several parties, including those who claim that no such analyses exist.

PP&L received several interrogatories which requested studies and supporting calculations concerning the shortening of the depreciation lives in question -- the first of which was Office of Trial Staff Interrogatory OTS-RB-23D dated January 13, 1995. In responding to OTS-RB-23D, PP&L described an analysis which built on the analyses contained within PP&L's Five-Year Upgrade Plan for Coal-Fired Generation dated May 2, 1994. That analysis is the basis for the proposed shortening of the depreciation lives of Holtwood 17, Martins Creek 1 & 2, and

Sunbury 1, 2, 3 & 4. Witness Prisco acknowledges this interrogatory response and, in fact, quotes it extensively on pages 11 and 12 of his written direct testimony.

Witness Johnson testifying on behalf of the Office of Consumer Advocate states at page 9 of his direct testimony, "The Company has performed no analysis of any kind to justify advancing the deactivation dates of Sunbury, Martins Creek and Holtwood." However, Witness Johnson ignores the response to Question 86 of Office of Consumer Advocate Interrogatory, Set IV, Dated February 1, 1995. That response provides identical information to that provided in response to OTS-RB-23D.

Witness Kollen of the PP&L Industrial Alliance correctly notes in his written direct testimony on page 14 that PP&L "was requested to provide all studies relied upon to revise its projected retirement dates for the generating facilities identified on Exhibit DAK-4 (PP&L *Industrial Alliance, Set II, Q. 13 and Office of Consumer Advocate, Set IV, Q. 86*)." The response to Question 13 of Interrogatories of the PP&L Industrial Alliance, Set II, Dated February 6, 1995 provides information identical to that provided to the OTS and the OCA. However, Witness Kollen erroneously states at line 11 of page 14, "In response to these requests, the Company provided its Five-Year Upgrade Plan for Coal-Fired Generation previously filed with the Commission in accordance with Pennsylvania statutory requirements." Witness Kollen fails to acknowledge that the full response provides the Five-Year Upgrade Plan filed in May, 1994 as the starting point for a more complete and up-to-date analysis which is described in the full interrogatory response.

Q. Please describe the analysis which supports the shortening of the depreciation lives in question.

A. As I have stated, the starting point for the analysis is the study dated May 2, 1994 and titled Five-Year Upgrade Plan for Coal-Fired Generation. That study is 132 pages long and includes individual chapters which address Holtwood 17, Martins Creek 1 & 2, and Sunbury 1, 2, 3 & 4. For each of those generating stations, there is an analysis which compares the revenue requirements projected to result from continued operation over a 20-year horizon to those projected to result from shutdown and retirement at the end of 1997.

As described in the various interrogatory responses, the analysis which supports the shortening of depreciation lives expands on this simple analysis. It notes, at the outset, that while the initial analysis favors the continued operation of the units in question, the margin by which continued operation is favored is relatively small. It goes on to state that this means that changes in the base assumptions could easily result in a different answer; i.e., that retirement might be favored instead. Finally, it points to two environmental requirements not recognized in the original May 2, 1994 analysis as examples of the kind of changes which might favor retirement. These environmental requirements are for significant additional reductions of NOx emissions under Title I of the 1990 Clean Air Act Amendments and reductions of air toxics under Title III of the 1990 Amendments. The analysis goes on, using Martins Creek as an example, to describe the types of equipment which might be required and the cost of installing and operating that equipment. It was assumed that a reader with the initial analysis in hand, could readily add the additional costs and observe, by inspection, the increased exposure to retirement in order to avoid incurring those costs.

In order to assure that there is no further confusion as to whether supporting analysis exists which employs economic data, I am submitting Exhibit DAK 5 which lays out, using pages from the May 2, 1994 study, the details of the Martins Creek analysis. Pages 1 through 5 of Exhibit DAK 5 are included in the May 2 study as Exhibits 6-2 through 6-6, respectively. Page 4 is a graph (derived from the spreadsheets on pages 1 and 2) which shows the cumulative present worth of the difference in revenue requirements between continued operation through 2013 and retirement in 1997. The result is a positive revenue requirement of $40 million indicating that retirement would be preferred. However, this calculation reflects, in addition to the costs of operation, only the value of the energy which would be produced; i.e., it does not reflect the value of the 300 MW of capacity provided by Martins Creek 1 & 2. The value of capacity is kept separate in this analysis because there are several different ways to attribute value which can lead to different results. In this case, the forecast PJM installed capacity rate was used which results in a $166 million value or a net $126 million benefit associated with continued operation. Hence, the May 2, 1994 study concluded that continued operation was a better choice than retirement in 1997.

As noted earlier, the May 2 study did not address certain critical issues, one of which is the need for additional environmental retrofits. As I indicated in my direct testimony, compliance dates for both Titles I and III are currently estimated to be 2003. The responses to the interrogatories cited earlier observed that Selective Catalytic Reduction might be required to achieve NOx reductions under Title I and ultra-high efficiency bag filters might be required under Title III. The interrogatory responses also provided cost estimates for this equipment which the Company is using for various planning purposes. Those cost estimates are translated into 2003-vintage dollars and are reflected on page 6 of Exhibit DAK 5, a spreadsheet titled "Continued Operation with Clean Air Exposure". Page 6 of Exhibit DAK 5 was not part of the May 2, 1994 study. It is a new spreadsheet which captures the elements that it was expected that a reader of the interrogatory responses would have grasped. Comparing the results on page 6 to those on page 1 indicates that the cumulative present worth of revenue requirements associated with the clean air exposures is $82 million; i.e., $258 million minus $176 million. Finally, page 7 of Exhibit DAK 5 compares continued operation with clean air exposures to retirement in 1997 with the result that the previous net benefit of $126 million absent the clean air exposures is now a net benefit of only $44 million -- a reduction of 65%.

Furthermore, a review of year-by-year results indicates that cumulative net benefits reach a maximum in 2002 and do not again reach that level until 2010. What this says is that an irrevocable commitment to continued operation today may not produce a net benefit compared to retirement until 2010 -- a date 15 years in the future. This means that if the clean air exposures do come to pass, the Company and its customers would have to wait 15 years to achieve a net benefit and, then, only if all other assumptions prove to be accurate over that period. In proposing a shorter depreciation life, PP&L is suggesting that a blind commitment to continued operation without recognizing the possibility of an earlier retirement is not a prudent investment strategy.

Q. Your description suggests an evolution in PP&L's understanding of the issues affecting the continued operation of these units. Is that a fair characterization?

A. Yes, it is. In fact the 1995 Annual Resource Planning Report filed with the PUC on May 1, 1995 contains the same type of analyses I just described. Exhibit DAK 6 summarizes the most recent results for Martins Creek 1 and 2 and is presented in the same format as page 7 of Exhibit DAK 5. It is significant to note that the forecast cumulative net benefit over the 20-year horizon is now only $19 million (instead of the $44 million in the previous analysis) and the cumulative net benefit actually peaks in 2003 at $25 million. These results suggest that continued operation beyond 2003 may not be justified.

Q. You stated earlier that the third issue raised in opposition to the Company's proposal is that future environmental costs are too speculative to consider as a threat to continued operation. How does the Company respond to this issue?

A. Witnesses Prisco (page 12 line 20) and Johnson (page 11 line 4) both characterize the environmental costs I have described above as too speculative to form the basis for a change in the lives of the plants in question. However, neither witness offers a yardstick which can be used to judge when a cost is too speculative. PP&L observes that both of the exposures, NOx and air toxics, exist in law under Title I and Title III of the 1990 Clean Air Act Amendments and, therefore, cannot be ignored. PP&L recognizes that, in both cases, scientific studies must be completed and regulations written. However, as can be seen from the analysis described above, ignoring these costs completely can result in outcomes which PP&L and its customers will come to regret. Considering these factors, PP&L concludes that these cost exposures must be recognized and failure to recognize them could be judged to be imprudent.

Q. Has PP&L taken these cost exposures into account for capital budgeting purposes?

A. Yes. As I indicated during my cross-examination, PP&L has rescoped a number of proposed capital additions. Furthermore, PP&L has reflected these efforts by excluding, from this proceeding, claims for construction work in progress for pollution control projects which are being re-scoped. PP&L has taken these actions out of a concern that failure to recognize the possibility of an earlier retirement date could increase unnecessarily the amount of undepreciated investment which would have to be recovered from customers at that time.

Q. You stated earlier that the fourth issue raised in opposition to the Company's proposal is that the 2003 dates proposed for depreciation purposes are not shown as retirement dates in its capacity plans. How does the Company respond to this issue?

A. Each of the four witnesses point to the fact that PP&L does not have a formal plan in place to retire these units in 2003 as a basis for rejecting the use of that date for purposes of calculating depreciation. However, the same criticism could be leveled against other generating units, including those for which lives were lengthened. This simply highlights the distinction between two different activities -- investment recovery and capacity planning. Furthermore, for the reasons I have described above, there is a significant likelihood that retirement may be dictated by events which are beyond our control.

Q. Does this conclude your response to the four broad areas of objection?

A. Yes, it does. However, there are several other points raised by Mr. Sivulich which I would like to address.

First, Mr. Sivulich offers Schedule 4 of OTS Exhibit No. 2 as proof of "sizeable capital additions to each of these units to continue their existence as long as economically possible." Schedule 4 is a tabulation of 24 capital additions and 1 set of coal contracts completed in order to comply with Title IV and Title I of the 1990 Clean Air Act Amendments. Mr. Sivulich's point would seem to be that PP&L has made significant investments which are not consistent with its proposal to advance certain deactivation dates to 2003. However, with the exception of the flue gas desulfurization system at Conemaugh 1 which does reflect a commitment to long-term operation, all of the remaining 23 capital additions are necessary to assure operation through 1995, not over a longer-term as Mr. Sivulich appears to suggest. Mr. Sivulich appeared to acknowledge this point under cross-examination when he stated that, with regard to Phase II compliance (Tr. 1695): "Based on discussions with PP&L's operating people and Mr. Krall, they indicated they would have to make decisions on which way to go in the compliance; whether or not its additional equipment or transferring credits from another unit, they haven't reached that point yet". Seeking additional clarification, ALJ Christianson asked, "But something has to be done"; to which Mr. Sivulich responded, "Something has to be done."

Unfortunately, on redirect examination, Mr. Sivulich read into the record a portion of Schedule 4 of OTS Exhibit No. 2 which states, "The following is a chronology of actions taken by PP&L to comply with both Title IV (Phases I and II) and Title I", The intent of this would seem to be to leave the impression that the projects listed in Schedule 4 were undertaken to enable PP&L to continue to operate these units indefinitely. This is simply not the case.

In order to assure that there is no misunderstanding on this point, the following summarizes these additions and their compliance dates:

Continuous Emissions Monitors (CEMs): Eleven (11) projects required by 11/15/93 on Phase I units and by 1/1/95 on Phase II units. Units are in violation of the Clean Air Act if they operate beyond those dates without CEMs.

Low NOx Burners (LNBs): Nine (9) projects required by 1/1/95 for Phase I units and by 5/31/95 for all units under Title I (Reasonably Available Control Technology or "RACT"). Phase I requirements have been delayed through settlement of a law suit. Units are in violation of Pennsylvania's RACT regulation if they operate beyond 5/31/95 without approved RACT installations.

Precipitator Upgrades: Three (3) projects required to accommodate lower sulfur coal needed after 1/1/95 at Phase I units to operate within limited distribution of SO_2 emission allowances.

The Conemaugh flue gas desulfurization system provides over-compliance with Phase I of Title IV, but is consistent with a long-term strategy which recognizes the tighter SO_2 emissions limits in Phase II. As PP&L has acknowledged in numerous documents, including its annual report to shareholders and Annual Resource Planning Report, the Company would have to take significant additional actions to reduce SO_2 emissions in order to comply with the Phase II requirements.

Q. Are there other points you wish to address regarding this portion of Mr. Sivulich's testimony?

A. Yes. Mr. Sivulich seemed to suggest during cross-examination that PP&L might choose to comply with Phase II of Title IV of the 1990 Clean Air Act Amendments by "installing additional equipment or transferring credits from another unit" (Tr. 1696). Mr. Sivulich's statement could be interpreted to mean that transferring credits is a no-cost compliance technique because it simply moves emission credits which were allocated by the EPA at no cost. I want the record to be clear that the "transfer" of credits should be viewed as a "purchase" of credits and, indeed, has a very real cost. This is best illustrated by a simple example. Title IV achieves nationwide reductions in SO_2 emissions by allocating a <u>limited</u> number of credits to individual power plants. In Phase II, for example, the number of credits is limited to the number which would result in emissions of 1.2 lbs. SO_2 per million Btu of heat input (1.2 lbs. SO_2/mmBtu). Consider, for example, Sunbury 1 -- a Phase II unit. If Sunbury 1 were to continue to burn its current fuel with no flue gas desulfurization equipment, its emissions would be approximately 3.5 lbs. SO_2/mmBtu. Its allocation of emission credits will not support emissions at this level and, therefore, if fuel changes and equipment additions were to be avoided, Sunbury 1 would have to acquire credits from a power plant which was emitting at a rate below 1.2 lbs. SO_2/mmBtu. Conemaugh would be such a unit. With its flue gas desulfurization equipment in service, Conemaugh emissions will be .15 to .20 lbs. SO_2/mmBtu, well under 1.2 lbs. SO_2/mmBtu and at a level which leaves unused credits available. However, the owners of Conemaugh would be foolish to simply give these allowances away given their investment in making them available and, also, the benefit Sunbury 1 would realize in terms of avoided equipment costs or fuel premiums. Thus, the "transfer" of emission credits is clearly a transaction which involves a seller and a purchaser, and there is clearly a cost involved in the acquisition of credits. The fact that PP&L is both a part owner of Conemaugh and sole owner of Sunbury 1 does not change this fact because Sunbury 1 will be competing with other units which will be willing to pay to acquire Conemaugh's credits. It is this competition which establishes a market price for emissions credits.

Q. Do you have any other comments regarding this portion of Mr. Sivulich's testimony?

A. Yes. At page 27, Mr. Sivulich states that investments should be made in "units to continue their existence AS LONG AS ECONOMICALLY POSSIBLE" (emphasis added). The point of our analyses has been that, for Holtwood 17, Martins Creek 1 & 2, and Sunbury 1, 2, 3 & 4, there are costly exposures which could render those plants economically obsolete. Furthermore, as I have previously indicated, PP&L has altered its investment strategy in these units because of a concern that their continued operation may become economically undesirable.

Q. Are there other points raised by Mr. Sivulich which you wish to address?

A. Yes. At page 27, Mr. Sivulich asserts that "PP&L is maintaining all of its generating units to ENSURE MAXIMUM LIFE SPANS" (emphasis added). Mr. Sivulich does not offer any basis for his assertion other than his apparent misunderstanding of the purpose of the projects set forth in his Schedule 4. In fact, PP&L is not maintaining any of its generating units to ensure MAXIMUM lives and I must reiterate that achieving maximum lives may <u>not</u> be in the best interest of PP&L's customers. As should be evident from the analyses I have provided and the investment strategies being pursued, it is PP&L's intent to achieve those lives which are cost effective and achieve the lowest revenue requirements.

Q. In addition, at page 26, Mr. Sivulich asserts that there is "an industry trend of maintaining, upgrading, and extending the life spans of fossil fueled power plants as a less costly option to building new power production plants." In responding to Question 7 of PP&L's Interrogatories to the Office of Trial Staff, Set IV, Mr. Sivulich stated that his assertion was based on two documents: a report entitled "Electric Power Outlook for Pennsylvania 1993-2013" prepared by the PUC's Bureau of Economics & Energy Planning and PP&L's May 1994 Resource Planning Report. I have already described how PP&L has updated and expanded its May 1994 studies.

With regard to the "Electric Power Outlook" report, Mr. Sivulich quotes several paragraphs from pages 31 and 32 which note UGI Luzerne Division's current plans to retire Hunlock Unit 3 in 2004. Hunlock 3 is a steam station which was placed in service in 1959 and is fired by anthracite silt. Hunlock 3's boiler is virtually identical to the Sunbury boilers 1A, 1B, 2A, and 2B (installed in 1949) which supply steam to Sunbury 1 and 2. The boiler at Holtwood 17 (installed in 1956) is a slightly larger version of the same design. Sunbury 1 and 2, and Holtwood burn the same fuel as Hunlock -- anthracite silt. PP&L engineers have discussed with UGI the problems of retrofitting this type of boiler for reduced NOx emissions. UGI's tentatively planned retirement of a somewhat newer generating station is consistent with PP&L's finding of threats to the continued operation of Sunbury and Holtwood, in particular, and smaller, older generating units, in general, beyond the 2003 timeframe.

Finally, under redirect examination (Tr. 1701), Mr. Sivulich stated that the chronological age of units does not impact his belief that the lives of the units in question can be extended. He stated, instead, that it is the "average dollar age of the investment that is used for depreciation" and suggests that the average dollar age is a more important factor in determining remaining life. PP&L acknowledges that significant investments have been made in extending the lives of these units beyond their normal 30 to 40 year lives and, therefore, the "age" of the plant on the basis of investment averaged by vintage is less than the chronological age. However, there are two shortcomings with using this as a valid measure of expected life:

1. The averaging of dollars of different vintages leads to a misleading result because it fails to account for inflationary effects. For example, a 1950-vintage component purchased today will cost significantly more than that

component cost in 1950. Consequently, if that component accounted for 50% of the investment in 1950, it could conceivably account for 90% of the investment today. The resultant "average dollar age" would be only a few years -- totally masking the fact that half of the physical equipment is 45 years old.

2. The equipment that PP&L has replaced does not necessarily reflect the most critical components affecting life extension; i.e., turbine pedestals, structural steel, boiler drums, and boiler headers. None of these components have been replaced at any of the units in question. They are very difficult and costly to replace, and the need to replace any of these could render continued operation economically unattractive. The true age of these components is their chronological age -- not an "average dollar age". Consequently, the chronological age of the generating unit is clearly relevant to expectations of remaining life.

Q. Does that complete your testimony?

A. Yes, it does.

EXHIBIT DAK 5

Exhibit 6-2
Martins Creek 1&2
Revenue Requirements
Continued Operation

Year	Beginning Plant Balance (MM$)	Capital Additions (MM$)	Carrying charges (MM$)	Generation (GWH)	Energy Value (MM$)	Fuel (MM$)	O&M (MM$)	Annual Present Worth Revenue Requirement (MM$)	Cumulative Present Worth Revenue Requirement (MM$)
1994	110.4	25.8	26.8	1,222	39.5	21.5	14.6	21.4	21
1995	130.0	0.0	28.6	1,284	39.2	23.2	15.1	23.3	45
1996	123.2	2.4	27.8	1,232	39.6	23.3	15.6	20.8	65
1997	118.7	2.2	27.1	1,269	41.5	24.6	16.2	18.5	84
1998	113.8	2.3	26.5	1,297	43.1	25.9	16.8	16.8	101
1999	108.9	2.4	25.8	1,408	46.8	29.1	17.3	15.0	116
2000	104.0	2.4	25.1	1,363	44.8	29.1	17.9	14.8	131
2001	98.9	2.5	24.5	1,378	47.8	30.4	18.6	12.7	143
2002	93.7	2.6	23.8	1,416	49.8	32.3	19.2	11.6	155
2003	88.4	2.7	23.2	1,583	63.5	37.2	19.9	7.0	162
2004	82.9	2.8	22.5	1,640	70.8	39.8	20.6	4.6	167
2005	77.3	2.9	21.9	1,688	70.4	42.4	21.3	5.3	172
2006	71.5	3.0	21.3	1,682	72.9	43.6	22.1	4.5	176
2007	65.3	3.1	20.7	1,776	89.8	47.6	22.8	0.4	177
2008	58.9	3.2	20.2	1,809	87.6	50.1	23.6	1.7	178
2009	52.0	3.3	19.7	1,846	97.4	52.9	24.5	(0.1)	178
2010	44.6	3.4	19.3	1,831	102.4	54.2	25.3	(0.8)	178
2011	36.5	3.6	19.1	1,867	103.6	57.1	26.2	(0.3)	177
2012	27.3	3.7	19.3	1,926	111.5	61.0	27.1	(0.8)	177
2013	16.4	3.8	21.2	1,946	115.2	63.7	28.1	(0.4)	176

Exhibit 6-3

Martins Creek 1&2
Revenue Requirements
1997 Retirement

Year	Beginning Plant Balance (MM$)	Capital Additions (MM$)	Carrying charges (MM$)	Generation (GWH)	Energy Value (MM$)	Fuel (MM$)	O&M (MM$)	Annual Present Worth Revenue Requirement (MM$)	Cumulative Present Worth Revenue Requirement (MM$)
1994	110.4	25.8	26.8	1,222	39.5	21.5	14.6	21.4	21
1995	130.0	0.0	28.6	1,284	39.2	23.2	15.1	23.3	45
1996	123.2	0.0	27.5	1,232	39.6	23.3	15.6	20.6	65
1997	116.3	0.0	26.3	1,269	41.5	24.6	16.2	18.0	83
1998	96.9	0.0	19.4	0	0.0	0.0	0.0	12.5	96
1999	77.6	0.0	19.4	0	0.0	0.0	0.0	11.4	107
2000	58.2	0.0	19.4	0	0.0	0.0	0.0	10.5	118
2001	38.8	0.0	19.4	0	0.0	0.0	0.0	9.6	127
2002	19.4	0.0	19.4	0	0.0	0.0	0.0	8.8	136
2003	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2004	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2005	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2006	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2007	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2008	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2009	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2010	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2011	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2012	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136
2013	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	136

Exhibit 6-4
Martins Creek SES
Annual Revenue Requirement
Operate Versus 1997 Retirement

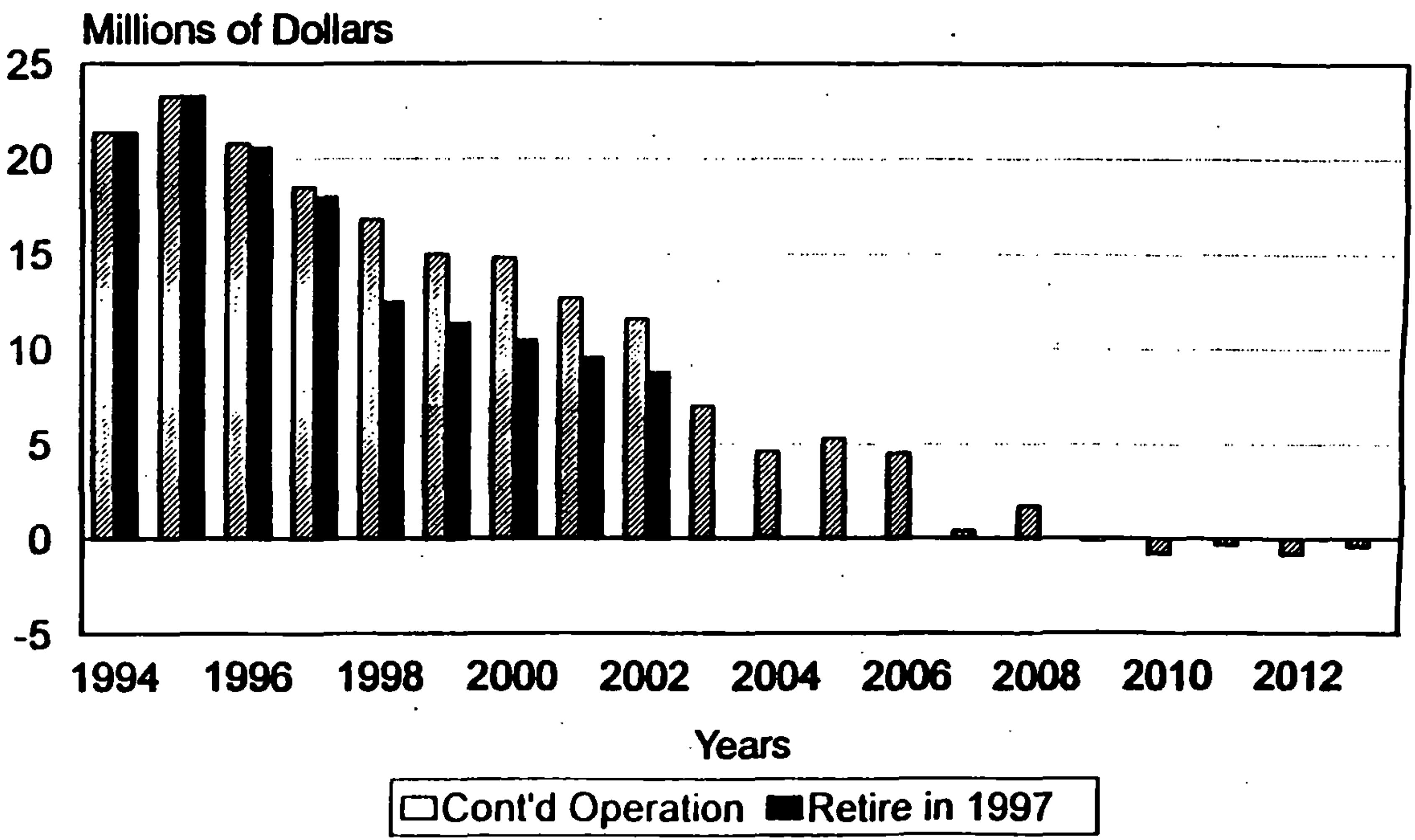

Exhibit DAK 5
Page 3 of 7

Exhibit 6-5
Martins Creek SES
Difference in Revenue Requirements
Operate Minus 1997 Retirement

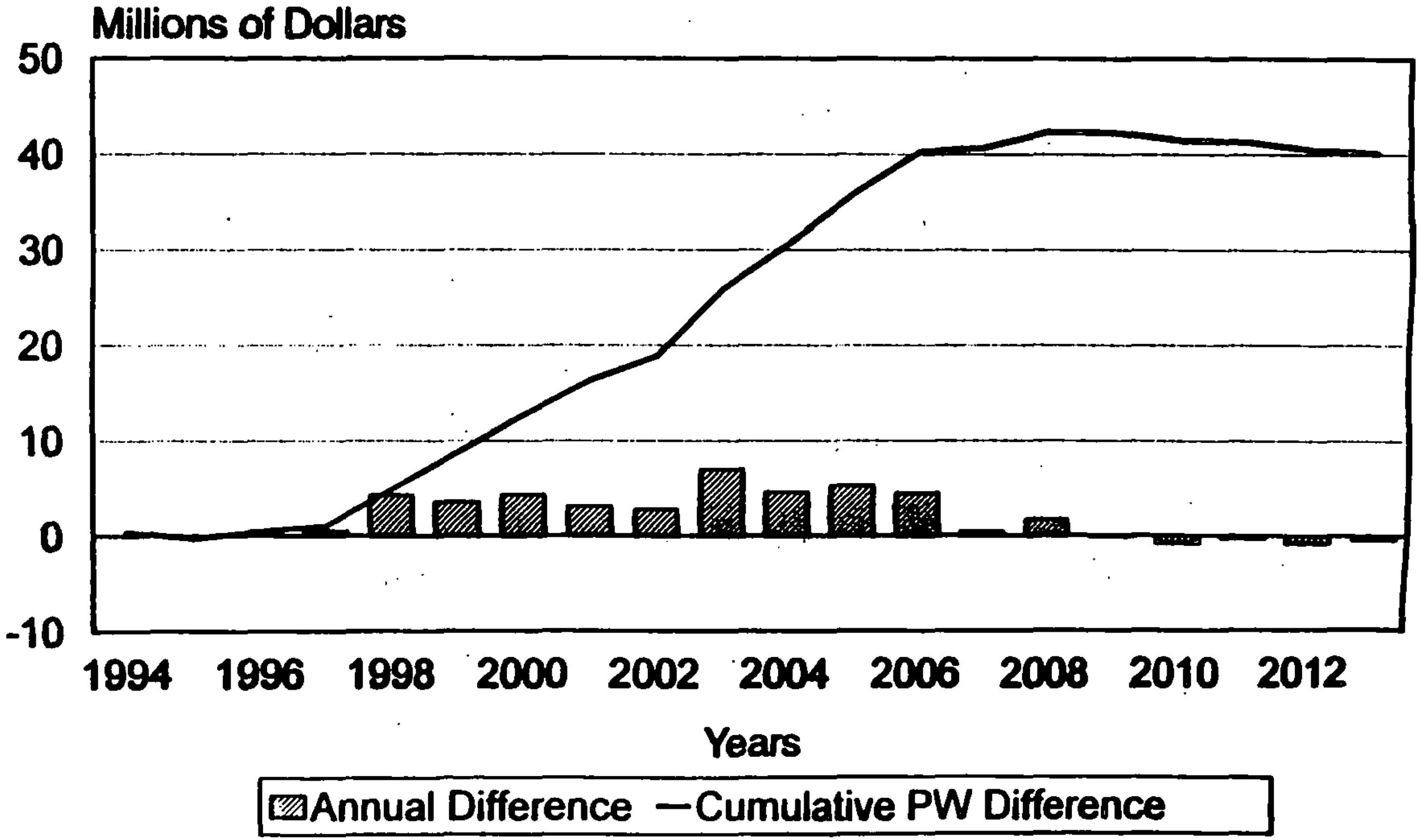

Exhibit DAK 5
Page 4 of 7

Exhibit 6-6
Martins Creek SES
Capacity Value

Year	Capacity Value MM$	PWF	PW Net Capacity Value MM$	Cum PW Net Value MM$
1998	8.0	0.704	5.6	5.6
1999	11.1	0.645	7.1	12.8
2000	14.4	0.590	8.5	21.3
2001	18.0	0.541	9.7	31.0
2002	21.8	0.495	10.8	41.8
2003	25.9	0.454	11.8	53.5
2004	30.3	0.415	12.6	66.1
2005	35.0	0.381	13.3	79.5
2006	36.5	0.349	12.7	92.2
2007	37.9	0.319	12.1	104.3
2008	39.4	0.292	11.5	115.8
2009	41.0	0.268	11.0	126.8
2010	42.7	0.245	10.5	137.3
2011	44.3	0.225	10.0	147.2
2012	46.1	0.206	9.5	156.7
2013	48.0	0.188	9.0	165.8

Martins Creek 1&2
Revenue Requirements
Continued Operation with Clean Air Exposure

Year	Beginning Plant Balance (MM$)	Capital Additions (MM$)	Carrying charges (MM$)	Generation (GWH)	Energy Value (MM$)	Fuel (MM$)	O&M (MM$)	Annual Present Worth Revenue Requirement (MM$)	Cumulative Present Worth Revenue Requirement (MM$)
1994	110.4	25.8	26.8	1,222	39.5	21.5	14.6	21.4	21
1995	130.0	0.0	28.6	1,284	39.2	23.2	15.1	23.3	45
1996	123.2	2.4	27.8	1,232	39.6	23.3	15.6	20.8	65
1997	118.7	2.2	27.1	1,269	41.5	24.6	16.2	18.5	84
1998	113.8	2.3	26.5	1,297	43.1	25.9	16.8	16.8	101
1999	108.9	2.4	25.8	1,408	46.8	29.1	17.3	15.0	116
2000	104.0	2.4	25.1	1,363	44.8	29.1	17.9	14.8	131
2001	98.9	2.5	24.5	1,378	47.8	30.4	18.6	12.7	143
2002	93.7	2.6	23.8	1,416	49.8	32.3	19.2	11.6	155
2003	88.4	94.0	35.0	1,583	63.5	37.2	28.4	15.4	170
2004	170.1	2.8	45.8	1,640	70.8	39.8	29.4	16.8	187
2005	155.7	2.9	43.7	1,688	70.4	42.4	30.4	16.1	203
2006	141.2	3.0	41.7	1,682	72.9	43.6	31.5	14.0	217
2007	126.3	3.1	39.6	1,776	89.8	47.6	32.6	8.8	226
2008	111.2	3.2	37.6	1,809	87.6	50.1	33.7	9.1	235
2009	95.6	3.3	35.6	1,846	97.4	52.9	34.9	6.4	241
2010	79.5	3.4	33.8	1,831	102.4	54.2	36.1	4.9	246
2011	62.6	3.6	32.1	1,867	103.6	57.1	37.4	4.7	251
2012	44.7	3.7	30.9	1,926	111.5	61.0	38.7	3.6	255
2013	25.1	3.8	31.3	1,946	115.2	63.7	40.1	3.4	258

Martins Creek 1&2

Year	(1) Cumm. Pw. Rev. Require. Contd Op w/CAA MM$	(2) Cumm. Pw. Rev. Require. Retire in 1997 MM$	(3) Contd Op w/CAA Minus Retire in 1997 MM$	(4) Cumm. Pw. Net Capacity Value MM$	(5) Pw. Cap Value Minus Diff. in Contd Op and Retire in 1997 MM$
1994	21	21	0	0	0
1995	45	45	0	0	0
1996	65	65	0	0	0
1997	84	83	1	0	-1
1998	101	96	5	6	1
1999	116	107	9	13	4
2000	131	118	13	21	8
2001	143	127	16	31	15
2002	155	136	19	42	23
2003	170	136	34	54	20
2004	187	136	51	66	15
2005	203	136	67	80	13
2006	217	136	81	92	11
2007	226	136	90	104	14
2008	235	136	99	116	17
2009	241	136	105	127	22
2010	246	136	110	137	27
2011	251	136	115	147	32
2012	255	136	119	157	38
2013	258	136	122	166	44

Notes:

(1) From Page 6
(2) From Page 2
(3) Column (1) minus Column (2)
(4) From Page 5
(5) Column (4) minus Column (3)

EXHIBIT DAK 6

Exhibit 4-8

Martins Creek 1&2

Year	(1) Cumm. Pw. Rev. Require. Contd Op w/CAA MM$	(2) Cumm. Pw. Rev. Require. Retire in 1998 MM$	(3) Contd Op w/CAA Minus Retire in 1998 MM$	(4) Cumm. Pw. Net Capacity Value MM$	(5) Pw. Cap Value Minus Diff. in Contd Op and Retire in 1998 MM$
1999	112	108	4	7	3
2000	128	122	6	15	9
2001	143	134	9	24	15
2002	156	145	11	34	23
2003	176	156	20	45	25
2004	196	156	40	56	16
2005	212	156	56	66	10
2006	227	156	71	75	4
2007	240	156	84	85	1
2008	248	156	92	93	1
2009	256	156	100	102	2
2010	262	156	106	109	3
2011	265	156	109	117	8
2012	269	156	113	124	11
2013	272	156	116	131	15
2014	274	156	118	137	19

Notes:

(1) From Exhibit 4-7

(2) From Exhibit 4-3

(3) Column (1) minus Column (2)

(4) From Exhibit 4-6

(5) Column (4) minus Column (3)

Statement 12-R

R-943271 5/23/95
Hbg Dc

DOCKETED
MAY 25 1995

PENNSYLVANIA POWER & LIGHT COMPANY

Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Fair Rate of Return

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Pennsylvania Power & Light Company
Rebuttal Testimony of Paul R. Moul
Table of Contents

REBUTTAL TESTIMONY OF PAUL R. MOUL

Q. Mr. Moul, have you previously testified in this proceeding?

A. Yes. My direct testimony was admitted into evidence as PP&L Statement 12. I was cross-examined on that testimony at a hearing on March 21, 1995.

Scope of Testimony and Summary

Q. What is the purpose of your testimony?

A. Pennsylvania Power & Light Company ("PP&L" or the "Company") has requested that I respond to the testimony presented by Mr. Kevan L. Deardorff, a witness appearing on behalf of the Office of Trial Staff ("OTS"), Mr. Richard A. Baudino, a witness appearing on behalf of the PP&L Industrial Customer Alliance ("PPLICA"), and Mr. Matthew I. Kahal, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"). I will also briefly comment on the testimony submitted by Mr. Thomas J. Prisco, a witness for the Department of Defense (DOD), concerning his position on the Company's rate of return. I will also submit updated calculations of the cost of equity as a supplement to the material contained in my direct testimony, Statement 12, and Exhibit PRM-1.

Q. Have you prepared an exhibit to accompany your rebuttal testimony?

A. Yes. Six (6) schedules, comprising Exhibit PRM-2, were prepared in connection with my rebuttal testimony. I have also presented Exhibit PRM-3 in support of the Company's future test year capital structure.

Updated Rate of Return

Q. Have you updated your cost of equity recommendation?

A. Yes. Based upon market data available through March 1995, my cost of equity recommendation for PP&L remains at 13.00%. The details supporting my recommendation using updated data are shown on page 1 of Schedule 1. For comparative purposes, page 2 of Schedule 1, provides the data which I used in developing my original recommendation as set forth in my direct testimony, Statement 12. In my update, I have moved forward my market evidence by five months, i.e., from October 1994 to March 1995. I should note that my update was calculated in accordance with the same methodology that I originally used in my direct testimony and simply reflects more current market data.

Q. Will you describe the reason that you have not reduced your cost of equity in light of declining interest rates?

A. Preliminarily, I should note that the market data that I employed in my original direct testimony ended near the cyclical peak of interest rates which was reached in November 1994. That peak occurred after a significant rise in long-term interest rates which began in October 1993. During the past five months, long-term interest rates have declined about one-half percentage point (i.e., 0.50%) using long-term Treasury bond yields as a benchmark. In my direct testimony, I noted that all measures of the Company's cost of equity were well above 13.00%, except the results of the DCF model. When I prepared my direct testimony, the indications pointed to a cost of equity of 13.45% as an average of the methods using PP&L data and 13.29% as an average of the methods using the Barometer Group data (see page 2 of

Schedule 1 for details). In the case of the updates (see page 1 of Schedule 1), the average results for PP&L and the Barometer Group have declined to 13.15% and 12.99%, respectively. As reflected in those updates, lower interest rates during the past five months have reduced my Risk Premium and CAPM cost rates. There has been a negligible change in the Comparable Earnings results. However, viewing the results of the DCF model -- the only measure which shows a cost of equity less than 13.00% -- the PP&L results have remained virtually the same (i.e., 12.46% as an update vs. 12.49% originally). On balance, the recent data indicate that my original 13.00% rate of return on common equity continues to be appropriate for the Company today.

Opposing Party Witnesses' Rate of Return Testimony

Q. Will you identify the areas of controversy concerning the Company's fair rate of return?

A. The central areas of dispute in this case involve: (i) the appropriate capital structure ratios to be used to calculate the Company's weighted average cost of capital, (ii) the proper ratesetting treatment of the Company's cost of redeeming its high cost long-term debt and preferred/preference stock, (iii) whether the cost of equity recommendation will be acceptable to the financial community, (iv) the determination of a reasonable Discounted Cash Flow cost rate, and (v) whether other methods provide a reasonable measure of the Company's cost of equity. The results of alternative methodologies are necessary to confirm the reasonableness of any cost of equity recommendation. Moreover, the use of more than one method will provide a range of results which will add reliability to the analysis and provide complimentary evidence of the cost of equity. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors which motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.). After all, no matter which model or inputs are used to develop the cost of equity, the final result must provide the Company with an opportunity to experience the types of returns which are necessary to attract investors. It is my opinion that the recommendations of Messrs. Deardorff, Baudino, Kahal, and Prisco fail to meet this test in that they are too low by reference to alternate investment opportunities.

Q. You indicated that you would respond briefly to the rate of return portion of DOD witness Prisco's testimony. Do you believe that his rate of return proposal is reasonable?

A. No. DOD witness Prisco advocates that PP&L should receive the same rate of return on common equity which the Commission granted in the recent <u>West Penn Power Company</u> case (Docket No. R-942986). This rate of return on common equity is too low for the Company because PP&L's risk is higher than that of West Penn and capital cost rates have changed since that time.

As to the issue of risk, PP&L's risk is higher than West Penn because the Company has a lower bond rating (PP&L's rating is A-, while West Penn's rating is A+) and the Company business position is lower (PP&L's business position is "Average," while West Penn's business position is "High average") which means that PP&L's business risk is higher. In addition, interest rates at the time of the West Penn testimony were about one percentage point lower (i.e., 7.47% - 8.3% = 0.83%), as measured by the yield on A rated public utility bonds.

Q. Why, in your view, do the recommendations of Messrs. Deardorff, Baudino, and Kahal fail to provide an equity return that fulfills the test of *reasonableness by reference to alternative* investment opportunities?

A. The equity returns of the opposing party witnesses fail to adequately recognize the higher risk of common equity vis-a-vis lower risk long-term debt. Those rates of return on common equity are:

OTS witness Deardorff	10.63%
PPLICA witness Baudino	10.85%
OCA witness Kahal	11.10%

While interest rates have trended lower since the fourth quarter of 1994, the yield on A rated public utility bonds is forecast to be 8.30% - 8.50% according to the April 1, 1995 Blue Chip Financial Forecast. The risk spread between the recommended equity allowances by the opposing parties and the interest rate on public utility bonds is only 2.13%, 2.35% and 2.60%, respectively, using an 8.5% public utility bond yield as a benchmark. In my opinion, such a spread falls far short of the compensation required by equity investors for the increased risk to which they are exposed, particularly in light of the increasing business risk of the electric utility industry and PP&L. As noted by Chairman Quain in his statement on the polling of the cost of equity in the West Penn Power Company case, a cost of equity just 200 basis points over current utility bond yields is insufficient to overcome the risk reality in utility stocks. Moreover, the recommendations by the witnesses representing the opposing parties have failed to reflect that the rate of return provided in this proceeding represents an opportunity rate which is not likely to be achieved because of attrition and regulatory lag and that PP&L's bond rating was downgraded during the historic test year to an A-.

Q. Can you provide an objective assessment of the positions taken by the opposing party witnesses concerning the Company's cost of equity?

A. If adopted by the Commission, the rates of return on common equity recommended by Messrs. Deardorff, Baudino, and Kahal would seriously jeopardize the Company's standing in the capital markets. In particular, the rates of return on common equity advocated by the opposing party witnesses would not support PP&L's financial integrity. As a demonstration of the inadequacy of these recommendations, the Company's earnings per share can be calculated from each recommendation and those earnings can be tested to determine whether they would adequately sustain the Company's dividend and hence, its stock price. This analysis begins with the book value per share of PP&L's common stock which was $15.79 at December 31, 1994. With each witness' recommended return on equity, I have calculated PP&L's earnings per share and resulting amount of potential retained earnings per share after payment of the Company's current dividend. From these figures, I have also calculated the related retention growth rates and have compared those rates with the growth rates advocated by each witness.

Witness	Recommended ROE	PP&L Book Value	Earnings Per Share	Dividends Per Share	Amount Retained Per Share	Calculated Growth Rate	Recommended Growth Rate
Deardorff	10.63%	$15.79	$1.68	$1.67	$0.01	0.06%	2.75%
Buadino	10.85	15.79	1.71	1.67	0.04	0.25	2.05-3.05
Kahal	11.10	15.79	1.75	1.67	0.08	0.51	2.5-3.0

It is quite obvious from the comparisons provided above that the opposing party witnesses have provided little, if any, earnings cushion above the Company's current dividend. Moreover, the rate of return on common equity of each witness does not come close to providing the growth rates each witness claims to use in his DCF analysis. Either these witnesses have misapplied the DCF model or they have seriously misinterpreted investor growth expectations for the Company.

Q. What rate of return on common equity is necessary to adequately reflect analysts' forecasts of earnings per share for the Company?

A. The earnings per share that are necessary to conform with analysts' forecasts for PP&L's are $2.05 ($15.79 × .1300) which is reflective of my rate of return recommendation. This earnings level compares with the forecasts of 1996 earnings per share of $2.05 by Value Line, $1.97 as the mean "Street Estimates" published in the S&P Earnings Guide, and $2.03/$2.05 (mean/median) as published by IBES. Further, the earnings per share calculated with the rates of return of the witnesses for the opposing parties would be in the range of $1.68-$1.75 and would result in an earnings level the Company has not experienced since 1987, setting aside 1994 performance which was affected by one-time charges. This shows that the recommendations of the witnesses representing the opposing parties are far off the mark and would provide almost no cushion (i.e., within the range of $0.01 to $0.08 per share) for the Company's current dividend. Hence, the rate of return recommendations by witnesses for the opposing parties do not conform with investor expectations and, if adopted, would be punitive to existing shareholders and impede the sale of new stock.

Capital Structure Ratios

Q. Are the capital structure ratios proposed by Mr. Kahal adequate to compensate the Company for the full cost of the call premiums on the redemption of high cost long-term debt?

A. No. Mr. Kahal's proposed capital structure ratios fail to reflect the capital structure adjustment necessary to fully recover the cost of redeeming high cost long-term debt. Although Mr. Kahal recognizes that the recovery of the annual cost should be reflected in the Company's cost of debt, he unfairly lowers the Company's equity ratio by failing to recognize the Company's adjustment. Moreover, Mr. Kahal's approach provides a serious mismatch of the long-term debt dollars used to compute his capital structure ratios and the long-term debt dollars used to compute the embedded cost of long-term debt.

Schedule 2 of Exhibit PRM-2 demonstrates that absent the capital structure adjustment to the long-term debt for the unamortized call premiums, the Company is unfairly penalized for undertaking these refinancings which benefit both PP&L and its customers. This is because the Company's capital structure is skewed by the amount of additional debt that was sold to finance the call premiums. Since those amounts have not been included in the Company's rate base for a return, the debt amount outstanding must be reduced by the unamortized call premiums in order to restore the capital structure to its status before the call. The Commission has recognized this principle in prior rate proceedings. Indeed, the Commission specifically rejected a similar adjustment proposed by Mr. Kahal in a 1990 rate case involving National Fuel Gas Distribution Company at Docket No. R-901670.

Q. Does Mr. Kahal's demonstration that his position reducing the Company's revenue requirement justify the rejection of your proposed capital structure?

A. No. Proving that an erroneous position reduces the Company's revenue requirement in no way justifies the denial of the full recovery of prudently incurred costs.

Q. Please comment on Mr. Baudino's capital structure proposal.

A. His proposal provides no basis upon which to set the Company's rate of return. Similar to Mr. Kahal's mismatch of capital dollars used to compute the capital structure ratios and embedded cost rates of senior capital, Mr. Baudino further mismatches future test year embedded costs with the historical test year end capital structure. The result is entirely meaningless. In support of this indefensible position, Mr. Baudino asserts that the Company has not supported the reasonableness of its projected capital structure. In fact, the Company has supported its proposed capital structure which moves toward less debt and more equity in response to comments by the bond rating agencies that the Company's debt ratio has been too high historically. A higher common equity ratio is the correct response to the increasing business risk developing in the electric utility industry.

Q. Mr. Baudino, also challenges the propriety of the Company's future test year end level of common equity. During his cross-examination, PPLICA witness Baudino reiterated his position on this matter by setting forth four criteria which he views to be necessary to substantiate PP&L's proposed equity financing. Will you respond?

A. Based upon my analysis of PP&L's situation, the future test year capital structure represents the proper basis to set the Company's rate of return in this case. In response to PPLICA witness Baudino's testimony on this matter, PP&L's proposed equity financing is reasonable because (1) it is economical in that it strengthens the underlying equity of the Company at a time of increased business risk; (2) the entire net proceeds from the sale of 5,000,000 shares (plus over-allotment of 750,000 shares) of PP&L Resources, Inc. common stock will be invested in PP&L; (3) the proposed equity financing will become a permanent component of the Company's capital structure and is not intended to inflate the revenue requirement in this case because the additional equity is necessary to position the Company to deal with increased competitive risks and the requirements of the bond rating agencies; and (4) the Company is prepared to verify that the equity financing has been accomplished when it is completed.

In further support of the future test year end capital structure ratios, it should be noted that the Company's ratios are reasonable by reference to those of Mr. Baudino's Comparison Group companies. In this regard, the Comparison Group average capital structure ratios are:

	1993 Historical	1994 Projected	1995 Projected
Common Equity	49.34%	49.43%	49.35%
Preferred Stock	5.59	6.34	5.31
Long-Term Debt	45.08	44.24	45.34

Given these comparisons taken from Mr. Baudino's Comparison Group, the Company's future test year end capital structure comprised of 45.88% common equity, 7.59% preferred stock, and 46.53% long-term debt is reasonable.

Q. Do you have specific information concerning PP&L's the proposed equity issue?

A. Yes. The Board of Directors of PP&L Resources has authorized the issuance of new common shares -- a copy of their resolution is included in Exhibit PRM-3 as Schedule 1. The Company's Vice President - Finance, has informed me that PP&L Resources has already selected the lead underwriters for the common stock offering -- Morgan Stanley & Co., Merrill Lynch, and Prudential Securities. The printer's proof of the Registration Statement under the Securities Act of 1933 is currently being reviewed, with the expectation that the Registration Statement will be filed shortly with the Securities and Exchange Commission.

In the Registration Statement, PP&L Resources has indicated that the net proceeds from the stock issue will be contributed to the equity capital of PP&L. Those proceeds will be used to repay short-term debt which has previously been incurred to repurchase certain amounts of the Company's high cost 9 1/4% Series First Mortgage Bonds due 2019 and 9 3/8% Series First Mortgage Bonds due 2021. To date, the Company has actually repurchased $35,000,000 of the 9 1/4% Series at a cost of $37,691,250 and $50,250,000 of the 9 3/8% Series at a cost of $55,026,175 (see Trade Confirmations included as Schedule 2 of Exhibit PRM-3). These expenditures in the amount of $92,717,425 were undertaken by the Company in anticipation of an equity infusion from PP&L Resources. The two step financing plan was included in the Company's future test year capitalization as a necessary response to the increasing business risk in the electric utility business -- which necessitates a reduction in the Company's financial leverage -- and to halt any further deterioration in the Company's credit quality. Additional equity is necessary to respond to the more stringent financial criteria now required by the bond rating agencies. Moreover, the rating agencies have expressed a concern over the Company's high debt use in the past. The Company's financing plan is required to alleviate those concerns and represents a prudent course of action to help prevent further bond downgradings.

DCF Model

Q. Should only a single approach, such as DCF, be used to measure the cost of equity in this case?

A. No. In my opinion, no single approach is sufficiently reliable to adequately establish the cost of equity without further verification. This is particularly true today given the wide swings in share values and the overall financial market uncertainty experienced over the past several years. As such, the cost of equity should not be measured by reference to a single method. The use of a single method by Messrs. Deardorff, Baudino, and Kahal significantly reduces the value of their testimony in this case. This is because their testimony contains no point of reference which would allow an assessment of their DCF results. Although Mr. Baudino has shown an alternative method, he has improperly applied the CAPM approach and has instead used the DCF method which is unreflective of the Company's risk (an issue which I will cover later in my rebuttal). As I indicated in my direct testimony, the use of more than one method provides a superior basis for the cost of equity recommendation.

I should further explain that there is an element of circularity in the DCF model when applied in public utility rate cases. This is because investors' expectations for the future depend upon regulatory decisions. Therefore, the use of the DCF in rate cases ensures that regulators will continue to provide high growth utilities with a return which sustains that performance. On the other hand, the use of the DCF for low growth companies perpetuates that performance and hinders any improvement. This then will reinforce investors' expectations that regulators will grant returns which guarantee low growth. In essence, due to this circularity, the DCF model may not fully reflect the true risk of a utility because the model may not deal with the high risk traits of a utility with low growth caused by poor accounting returns.

Q. Mr. Kahal disputes your claim that the DCF model is circular in the public utility ratesetting context. Will you respond?

A. Yes. Mr. Kahal agrees that investor expectations can be influenced by anticipated regulatory decisions. He indicates, however, that the key is not <u>why</u> investors hold a particular view of growth, but rather <u>what</u> growth they are expecting. However, as I have shown, his recommendation provides a level of *growth which is far below what he believes investors actually* expect. On one hand he argues that investors expect growth for PP&L in the range of 2.5% to 3.0% while, at the same time, he provides the Company with an opportunity to experience growth of only 0.51%. These positions are internally inconsistent and *would not maintain the Company's stock price equilibrium, a* requirement of the DCF.

Q. Mr. Kahal indicates that the DCF method is probably the most widely used approach to set the return on equity. Does this justify exclusive use of the DCF?

A. No. The investment community uses the DCF model and other models in its analysis of common stocks. Likewise, regulators follow a practice which includes multiple methods. While the Commission has used the DCF method in prior rate case decisions, other methods have also been considered. Moreover, the Commission has responded to an NARUC survey and indicated that multiple methods are considered. As noted by the survey results contained in Schedule 3 of Exhibit PRM-2, other methods cited in the survey include the Comparable Earnings method. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors which motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.).

Q. What form of the DCF model has been employed in this case?

A. The constant growth or "Gordon" form of the DCF model has been used by all rate of return witnesses in this case. It must be recognized that this version of the DCF model is not without its limitations because many of the assumptions which must be made to utilize this model are simply not realistic. According to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same rate absent any change in price-earnings multiple. However, there is no evidence that these conditions actually prevail in the equity market.

Q. Are there other limitations to DCF which must be recognized when using the model in public utility rate cases?

A. Yes. As shown by the data presented on Schedule 4 of Exhibit PRM-2, it requires approximately 100 years of cash flows before the internal rate of return ("IRR") ceases to be affected by the injection of additional years of cash flows. In my example, a stock with a 6% expected dividend yield and a 6% dividend growth rate would have an 11.53% IRR after 50 years of cash flows -- a value well below the 12% indicated by the simplified DCF model. When the cash flows are extended to 100 years, the IRR becomes 11.98% -- a value close to the 12% shown by the simplified DCF formula. This shows that an investment horizon necessary to employ the simplified Gordon form of the DCF model extends well beyond the view of most investors.

Second, the turnover statistics of electric utility stocks indicate that the assumption of 50 or 100 years of cash flows does not correspond to the investment horizon of the typical stock investor. As shown by the data presented on Schedule 5 of Exhibit PRM-2, the actual investment horizon is more likely in the two to four year range.

DCF Dividend Yield

Q. Messrs. Deardorff and Kahal specifically challenge your ex-dividend adjustment. Please respond.

A. Preliminarily, I should note that Messrs. Deardorff and Kahal have adjusted the dividend yield component in a forward-looking manner with the formula D_0/P_0 (1 + .5g). I have also followed this procedure. In addition, I computed yields based on discrete quarterly dividend growth and quarterly compounding. These are entirely reasonable refinements to developing adjusted dividend yields. As for my adjustment to recognize the ex-dividend date, the opposing party witnesses may believe that this adjustment is unnecessary, but the availability of data through electronic sources and the increased use of personal computers have allowed this refinement to increase the accuracy of the dividend yield computation. In fact, the ex-dividend date adjustment has been accepted by the New York Public Service Commission in rate case decisions for several years.

DCF Growth Rate

Q. Can you show how the DCF model can be misapplied in a utility rate case?

A. The major infirmity of the DCF method becomes apparent when viewing the model in its retention growth rate form, as used, in part, by Messrs. Deardorff, Baudino, and Kahal. This form of the DCF merely adjusts the assumed return on book common equity by the difference between the dividend yield on book value and the dividend yield on market value. This form of the DCF cannot be viewed as a full market model because it mixes accounting returns and market returns.

Q. In his direct testimony, Mr. Kahal argues that the retention growth formula provides the principal measure of the DCF growth rate. Please comment.

A. Retention growth, along with external financing growth, is another means of describing book value per share growth. I have explained in my direct testimony (pages 41-42) some of the other factors which contribute to earnings growth that are not accounted for by the retention growth formula. The theory of DCF suggests that absent a change in price-earnings multiple, the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share. Hence, earnings per share form the basis for investors' capital gains yield and earnings are the source of dividend payments to investors. In my view, book value per share growth, or its surrogate retention growth, does not represent the proper financial variable to be considered when selecting the DCF growth component.

Q. Does retention growth provide a meaningful measure of the DCF growth rate in this proceeding?

A. No. Mr. Kahal prefers an internal/external growth analysis. In this regard, Mr. Kahal's assumptions include a 12.0% to 12.5% constant ROE, a 20% constant retention rate (complement of the payout ratio), and a constant external financing rate of 0.5% for his primary proxy group and for my barometer group. Mr. Kahal does not explain how his proxy group or my barometer group will earn a 12.0% to 12.5% ROE if their cost of equity is set at just 11.05% or 11.0%.

Q. Do you have any further comments with respect to Mr. Kahal's internal growth rate?

A. Yes. The Value Line figures cited by Mr. Kahal contain a downward bias because year-end book values are employed. The projected returns on equity would actually be higher when using average book values.

Q. Are there other factors which must be considered when formulating a DCF growth rate for an electric utility, such as PP&L?

A. If market models, such as DCF, are applied without full recognition of all factors (including qualitative factors) that influence investor expectations then market models should be avoided when setting the rate of return on common equity. In this regard, forecasts of earnings per share do not fully encompass market-wide factors because investors make independent assessments concerning these factors (i.e., their pricing decisions reflect general market sentiment). For that matter, it is not generally known to what extent securities analysts incorporate market-wide factors into their estimates, or whether analysts do this uniformly. While a consensus of estimates may help overcome these limitations, the relatively small coverage that many utilities receive blurs the underlying framework used to make the projections.

Further, fundamental analysis as employed in reaching a growth rate forecast cannot fully account for all market-wide factors because this type of growth analysis is company-specific. It should also be remembered that analysts' forecasts -- which take a short-term view of the future using accounting values -- are poor predictors of price appreciation. Valuations in the market are influenced by relative P/Es, dividend yields, interest rates, the supply of stocks, etc. In addition, it is reasonable to assume that recent forecasts by analysts for the electric utilities are overly conservative because no one can be sure of the winners/losers in the new business environment and/or how regulators will react.

Q. Please comment on Mr. Baudino's growth rate analysis.

A. Mr. Baudino's approach is results oriented and, in my opinion, lacks consistency. For example, to reach his growth rate conclusion he adopted the following measures of growth:

	Bottom of Range	Top of Range
PP&L	Sustainable Growth using Value Line forecasts	5 year/10 year historical growth
Comparison Group	Value Line EpS forecast, IBES EpS forecast, sustainable growth	10 year historical (excl. negatives)
Barometer Group	IBES EpS forecast, sustainable growth using Value Line forecast	Value Line Eps forecast, 10 yr. historical DpS, 10 year historical retention growth

From this tabulation, it is apparent that there is a lack of consistency by PPLICA witness Baudino in formulating his growth rate from group to group.

Q. Do you have any comments on the DCF results derived by Mr. Deardorff?

A. Yes. As previously indicated, Mr. Deardorff's DCF results are entirely too low. In addition, Mr. Deardorff's mechanical approach to the DCF using 5-year forecast Value Line projected growth in earnings, dividends, and book value produces wholly unrealistic results -- instances where the DCF calculations are as low as 9.25% for the Barometer Group and 9.40% for PP&L (see OTS Exhibit No. 1, Schedule 4 pages 3 and 7). Moreover, some of his Barometer Group companies had DCF calculations as low as 8.2% to 8.5%. Since Mr. Deardorff acknowledged that "A" rated public utility bonds are priced to yield 8.30% - 8.50%, no serious consideration can be given to these extraordinarily low figures.

Risk Premium Method

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, Risk Premium results should be given serious consideration, particularly under current market conditions. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides a foundation for the cost of equity which must be higher in recognition of the risk of equity which exceeds investors' risk of lending capital to a firm. As such, the Risk Premium results are more responsive to changes in the cost of capital than some other methods.

Response to Opposing Witnesses' Rebuttal

Q. Please respond to the testimony of the opposing parties concerning your Risk Premium approach.

A. Mr. Deardorff makes the unfounded assertion that while the Risk Premium and CAPM models are relevant to investors, that relevancy does not carry over to the ratesetting process. He also asserts, without support, that the Risk Premium and CAPM do not measure the current returns as directly as DCF. With the yield on A rated public utility bonds and the risk-free rate of return as components, these methods are just as direct as the DCF method.

Q. Does Mr. Kahal's Risk Premium approach provide a valid measure of the cost of equity?

A. No. Mr. Kahal's Risk Premium analysis starts with a DCF-derived equity cost rate. This approach was presented to and repeatedly rejected by the Commission in the early 1980s. Moreover, Mr. Kahal's analysis employs a generic FERC benchmark rate which was abandoned because it was not useful in setting the cost of equity. In fact, I am not aware of any case in which the FERC actually set its equity cost rate finding at the generic benchmark rate.

Q. Mr. Kahal also quarrels with the risk-free rate of return employed in your CAPM analysis. What is your basis for selecting the yield on long-term Treasury bonds as the risk-free rate of return?

A. For public utility ratesetting purposes, the yield on long-term Treasury obligations represents the correct focus for selecting the risk-free rate of return in the CAPM. Short-term instruments, such as Treasury bill yields, should not be used in a CAPM because they are subject to abrupt changes and can be highly volatile. In addition, a foremost authority on the CAPM, Professor Diana Harrington, has stated that "Anyone using the CAPM must choose the Rf proxy with great care. The most widely used proxies, 30- or 90-day Treasury bill rates, are empirically inadequate and theoretically suspect." (Modern Portfolio Theory and the Capital Asset Pricing Model, Prentice Hall, Inc., 1983, p. 108).

Q. Mr. Kahal has also objected to the market premium which you used in the CAPM. Will you comment?

A. Yes. I have considered not only historical results, but I have also used investor expected returns using the Value Line forecasts. It is important when using the CAPM that the total market return (combination of the risk free rate of return and the market risk premium) reflect reasonable expectations for the future. This is shown by reference to the Value Line forecast which projects a total market return of 15.94%. According to the April 14, 1995 Value Line Report, the estimated median appreciation potential is forecast to be 65% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 13.34% (i.e., $1.65^{.25}-1$). Combined with the Value Line dividend yield of 2.6%, the Value Line total return is 15.94% (13.34% + 2.6%) for the Value Line equities. As to Mr. Kahal's DCF calculation for the Value Line Industrial Composite (a different group than I employed), the components provide a mismatch of accounting returns and market returns which cannot be used as an input in the CAPM. The CAPM requires full use of market returns which would exclude the DCF-type calculation submitted by Mr. Kahal. These comparisons also do not prove his point because the Value Line forecasts reflect the capital appreciation on 1700 stocks, while the Value Line industrial composite which OCA witness Kahal employs is limited to just 810 stocks.

Q. Please respond to the opposing party witnesses' comments concerning your Comparable Earnings approach.

A. The Comparable Earnings approach was established in the landmark Bluefield & Hope decisions, which set forth the two principal standards of a fair return, namely, comparability and capital attraction. In the Hope decision, the United States Supreme Court defined these requirements as: "...by that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." The Comparable Earnings approach satisfies the comparability standard. As I have employed it, the Comparable Earnings approach uses both historical and forecast returns to set the rate of return.[1] This approach has been used by me in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill both established standards of a fair rate of return.

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1 There is no relevance to the percentage of institutional ownership of unregulated companies in the Comparable Earnings approach. Further, my use of the Financial Strength ranking deals with the capital structure issue of utilities and non-regulated firms.

<u>Company Risks</u>

Q. Have the opposing party witnesses adequately assessed the relative risk of PP&L?

A. No. Mr. Deardorff has ignored many of the developing risk factors which will impact the electric utility industry and PP&L. His assertions that the overall investment risk of utilities will decline further ignores the new risks of the industry.

Mr. Baudino makes the incredible assertion that PP&L has below average risk. As demonstrated in my direct testimony and shown by the comparisons set forth on Schedule 6 of Exhibit PRM-2, the Company's risk is about the same (albeit higher in certain instances) as that of the other barometer group utilities considered in this proceeding. Further, the credit rating agencies have indicated for a number of years that the Company's debt usage was high for its credit rating. Indeed, the Company's credit risk has increased recently due to the bond rating downgrading which occurred during the historic test year. Finally, if the recommendations by the opposing party witnesses in this case were adopted by the Commission, the Company's risk would increase substantially.

<u>Summary</u>

Q. Please summarize your rebuttal testimony.

A. In my opinion, the equity returns recommended by Messrs. Deardorff, Baudino, Kahal, and Prisco fail to adequately reflect the many factors which influence investors and, hence, the Company's cost of equity. Use of alternative methods to measure the cost of equity incorporate, by reference, the complex set of variables considered by investors when formulating expectations for the Company. This is because they evaluate, on a relative basis, the earnings of other similarly situated companies (foundation for comparable earnings approach), interest rates (the bond yield component of risk premium), and relative stock price performance (the beta measure of systematic risk in the CAPM). Since DCF does not directly address these issues, the recommendations of the opposing party witnesses significantly understate the Company's cost of equity. In addition, it is essential that the Commission recognize the Company's future test year capital structure proposed in this case because it is reflective of the conditions which will prevail during the rate effective period. Based on recent developments in the financial markets, I am convinced that my initial cost of equity proposal of 13.00% continues to be appropriate for the Company.

Q. How does your rate of return recommendations compare when viewed in the context of the credit quality financial benchmarks?

A. It is important to recognize that the levels of credit quality expected by the rating agencies represent results anticipated to be achieved, while the positions of the parties in this case represent merely opportunity rates for the Company. For the Company, pre-tax interest coverage must be near the 4.0 times threshold for the A rating. As noted by Mr. Hill,

> "The Company's minimum pre-tax coverage objective is tied to the objective of maintaining an "A" bond rating which requires a pre-tax coverage ratio of approximately 4.0× (the mid-point of an average and below average business position), with capital lease payments included as an interest component in this calculation."

The Company's proposed 10.22% overall rate of return provides an opportunity to experience 4.03 times pre-tax interest coverage and, therefore, represents a reasonable request in this case.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit PRM-2

PENNSYLVANIA POWER & LIGHT COMPANY

Schedules to Accompany

the Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Fair Rate of Return

Pennsylvania Power & Light Company
Summary of Updated Common Equity Recommendation

Discounted Cash Flow	Dividend Yield(1)		Growth Rate		Cost of Equity
PP&L	8.46%	+	4.00%	=	12.46%
Barometer Group	7.85%	+	4.00%	=	11.85%

Risk Premium Method	Prospective Yield		Risk Premium		Equity Cost Rate
PP&L	8.50%	+	4.75%	=	13.25%
Barometer Group	8.50%	+	4.75%	=	13.25%

Capital Asset Pricing Model	Rf	B (Rm - Rf)		k
Traditional				
PP&L	7.50%	+ .69 (7.67%)	=	12.79%
Barometer Group	7.50%	+ .68 (7.67%)	=	12.72%
Zero Beta				
PP&L	11.26%	+ .69 (3.86%)	=	13.92%
Barometer Group	11.26%	+ .68 (3.86%)	=	13.88%
Average of the CAPM Results				
PP&L				13.36%
meter Group				13.30%

parable Earnings	Historical	Forecast	Average
Non-Regulated Firms	12.60%	14.50%	13.55%

	Comparable Earnings	DCF	Risk Premium	CAPM	Average All Methods
PP&L	13.55%	12.46%	13.25%	13.36%	13.15%
Barometer Group	13.55%	11.85%	13.25%	13.30%	12.99%
Recommendation					13.00%

Note: (1) Adjusted for next period dividend growth.

Pennsylvania Power & Light Company
Summary of Initial Common Equity Recommendation

Discounted Cash Flow	Dividend Yield(1)		Growth Rate		Cost of Equity
PP&L	8.49%	+	4.00%	=	12.49%
Barometer Group	7.97%	+	4.00%	=	11.97%

Risk Premium Method	Prospective Yield		Risk Premium		Equity Cost Rate
PP&L	9.00%	+	4.75%	=	13.75%
Barometer Group	9.00%	+	4.75%	=	13.75%

Capital Asset Pricing Model	Rf		B (Rm - Rf)		k
Traditional					
PP&L	8.00%	+	.70 (7.85%)	=	13.50%
Barometer Group	8.00%	+	.68 (7.85%)	=	13.34%
Zero Beta					
PP&L	11.85%	+	.70 (3.95%)	=	14.62%
Barometer Group	11.85%	+	.68 (3.95%)	=	14.54%
Average of the CAPM Results					
PP&L					14.06%
meter Group					13.94%

parable Earnings	Historical	Forecast	Average
Non-Regulated Firms	12.60%	14.40%	13.50%

	Comparable Earnings	DCF	Risk Premium	CAPM	Average All Methods
PP&L	13.50%	12.49%	13.75%	14.06%	13.45%
Barometer Group	13.50%	11.97%	13.75%	13.94%	13.29%
Recommendation					13.00%

Note: (1) Adjusted for next period dividend growth.

Pennsylvania Power & Light Company
Capital Structure Implications of Call Premiums

Balance Sheet prior to Call of Debt

Assets		Capitalization		Capital Structure Ratios
Net Fixed Assets	$ 10,000	Debt	$ 5,000	50.00 %
		Equity	5,000	50.00
Total	$ 10,000	Total	$ 10,000	100.00 %

Balance Sheet after Call of Debt

Assets		Capitalization		Capital Structure Ratios
Net Fixed Assets	$ 10,000	Debt	$ 5,500	52.38 %
Call Premium	500	Equity	5,000	47.62
Total	$ 10,500	Total	$ 10,500	100.00 %

Ratesetting Treatment after Call of Debt

Assets		Capitalization		Capital Structure Ratios
Net Fixed Assets	$ 10,000	Debt	$ 5,500	
		less:Call Premium	(500)	
			5,000	50.00 %
		Equity	5,000	50.00
Total	$ 10,000	Total	$ 10,000	100.00 %

UTILITY REGULATORY POLICY IN THE UNITED STATES AND CANADA

COMPILATION 1993-1994

OF THE

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Paul Rodgers
Administrative Director and
General Counsel

Karon Bauer
Editor

Price: $70.00

SECTION 38

RATE OF RETURN

ELECTRIC UTILITIES

The rate of return established as fair and reasonable by an agency is the return that a utility may earn on its rate base - net investment in plant, equipment and working capital. A utility company is not guaranteed a specific rate of return by a regulatory authority but it is given an opportunity to earn a rate of return which is determined appropriate by an agency.

Table 213 shows the methods used by the agencies in determining the rate of return.

Table 214 displays the most recently approved rate of return on rate base for electric utilities and, when reported, the actual rate of return earned by the utilities. Table 215 displays the most recently approved rate of return on common equity for electric utilities and, when reported, the actual rate of return earned by the utilities.

TABLE 213 - AGENCY AUTHORITY OVER RATE OF RETURN - ELECTRIC UTILITIES

AGENCY	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return: No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Mid-point approach	** Capital asset pricing model	** Risk premium	Other	Duration of call protection provision influences judgment in determining rate of return
FERC	X	X	X	X							
ALABAMA PSC	X	X		X							
ALASKA PUC	X	X			X						Possible.
ARIZONA CC	X	X	X 2/								
ARKANSAS PSC	X		X	X 11/							
CALIFORNIA PUC	X	X 1/	X 2/	X	X			X	X	X	Possible.
COLORADO PUC	X	X		X 9/	X						
CONNECTICUT DPUC	X	X		X							
DELAWARE PSC	X		X 2/	X	X					X	
D.C. PSC	X	X		X							
FLORIDA PSC	X	X 1/	X 2/								
GEORGIA PSC	X	X	X 2/	X					X	X 8/	
HAWAII PUC	X	X	X 2/		X					X	
IDAHO PUC	X	X		X 9/	X	X					
ILLINOIS CC	X	X	X 2/				X			X	
INDIANA URC	X		X								
IOWA UB	X	X 1/	X	X					X	X 6/	
KANSAS SCC	X	X		X							
KENTUCKY PSC	X	X	X 2/	X	X	X	X			X	
LOUISIANA PSC	X			X							
MAINE PUC	X	10/	X 9/	X							
MARYLAND PSC	X	X		X						X 6/	
MASSACHUSETTS DPU	X	X		X 5/						X 5/	
MICHIGAN PSC	X	X	2/	X	X		X	X	X	X	
MINNESOTA PUC	X	X		X							
MISSISSIPPI PSC	X	X		X	X						
MISSOURI PSC	X	X		X							
MONTANA PSC	X	X		X	X						
NEBRASKA PSC 4/	X	X		X							
NEVADA PSC	X	X		X	X	X					
NEW HAMPSHIRE PUC	X	X		X							Yes
NEW JERSEY BPU 12/	X	X	X					X	X	X	
NEW MEXICO PUC	X	X	X 2/	X						X	
NEW YORK PSC	X	X	X	X 7/						X	
NORTH CAROLINA UC	X	X	X 2/	X	X			X	X	X	
NORTH DAKOTA PSC	X			X							
OHIO PUC	X	X	X	X 7/						X 7/	No decision.
OKLAHOMA CC	X	X		X	X			X	X		
OREGON PUC	X	X 1/		X				X			
PENNSYLVANIA PUC	X	X	X 2/	X	X	X	X			X	Maybe, if soon
RHODE ISLAND PUC	X	X	X	X	X					X 3/	
SOUTH CAROLINA PSC	X	X	X	X				X	X		
SOUTH DAKOTA PUC	X	X		X	X						
TENNESSEE PSC	X	X	X 2/	X	X	X	X	X	X		
TEXAS PUC	X	X	X 2/	X	X				X	X	
UTAH PSC	X	X		X							
VERMONT PSB 12/	X	X		X	X					X	
VIRGINIA SCC	X	X	X 2/								
WASHINGTON UTC	X	X		X							
WEST VIRGINIA PSC	X	X	X 2/	X	X			X	X	X	
WISCONSIN PSC	X	X	X 2/	X				X		X	
WYOMING PSC	X		X 2/	X	X			X		X	
PUERTO RICO PSC 12/											
VIRGIN ISLANDS PSC	X	10/	X 2/	X	X					X	
ALBERTA PUB	X	X	X 2/	X	X					X	
NOVA SCOTIA UARB	X	X	X 2/	X	X				X	X	
ONTARIO EB 12/	X	X	X 2/		X					X	

** For definitions of terms, please consult the Glossary of Terms at the back of this book. ICB=Case-by-Case Basis

FOOTNOTES - TABLE 213
AGENCY AUTHORITY OVER RATE OF RETURN

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment from equity.

2/ Commission favors no single method, but rather that which produces the most reasonable results.

3/ It may use any method it desires especially in the case of a small company.

4/ No Commission regulation of electric or gas utilities.

5/ DCF is preferred, but Department approves other methods which check DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also given serious consideration.

6/ DCF is preferred; all methods are considered including econometric modeling approach.

7/ No single method, however, discounted cash flow is frequently used.

8/ Discounted cash flow most often used, but risk premium method used also. Determined case by case.

9/ DCF has been the preferred method, but its results should be checked with other methods.

10/ Never an issue before this agency.

11/ Agency favors DCF, but any method presented is considered.

12/ Commission did not respond to request for update information; this data may not be current.

Schedule 4

Pennsylvania Power & Light Company
Internal Rate of Return Computation
Showing the Effect of 50 Years of Compounding
Verses 100 Years of Compounding

		50-Year		100-Year		
Growth Rate		6.00%		6.00%		
Cash Flows		($20.00)		($20.00)		
	1995	$1.200	1995	$1.200	2045	22.104
	1996	1.272	1996	1.272	2046	23.430
	1997	1.348	1997	1.348	2047	24.836
	1998	1.429	1998	1.429	2048	26.326
	1999	1.515	1999	1.515	2049	27.906
	2000	1.606	2000	1.606	2050	29.580
	2001	1.702	2001	1.702	2051	31.355
	2002	1.804	2002	1.804	2052	33.237
	2003	1.913	2003	1.913	2053	35.231
	2004	2.027	2004	2.027	2054	37.345
	2005	2.149	2005	2.149	2055	39.585
	2006	2.278	2006	2.278	2056	41.960
	2007	2.415	2007	2.415	2057	44.478
	2008	2.560	2008	2.560	2058	47.147
	2009	2.713	2009	2.713	2059	49.975
	2010	2.876	2010	2.876	2060	52.974
	2011	3.048	2011	3.048	2061	56.152
	2012	3.231	2012	3.231	2062	59.522
	2013	3.425	2013	3.425	2063	63.093
	2014	3.631	2014	3.631	2064	66.878
	2015	3.849	2015	3.849	2065	70.891
	2016	4.079	2016	4.079	2066	75.145
	2017	4.324	2017	4.324	2067	79.653
	2018	4.584	2018	4.584	2068	84.432
	2019	4.859	2019	4.859	2069	89.498
	2020	5.150	2020	5.150	2070	94.868
	2021	5.459	2021	5.459	2071	100.560
	2022	5.787	2022	5.787	2072	106.594
	2023	6.134	2023	6.134	2073	112.990
	2024	6.502	2024	6.502	2074	119.769
	2025	6.892	2025	6.892	2075	126.955
	2026	7.306	2026	7.306	2076	134.573
	2027	7.744	2027	7.744	2077	142.647
	2028	8.209	2028	8.209	2078	151.206
	2029	8.701	2029	8.701	2079	160.278
	2030	9.223	2030	9.223	2080	169.895
	2031	9.777	2031	9.777	2081	180.088
	2032	10.363	2032	10.363	2082	190.894
	2033	10.985	2033	10.985	2083	202.347
	2034	11.644	2034	11.644	2084	214.488
	2035	12.343	2035	12.343	2085	227.357
	2036	13.083	2036	13.083	2086	240.999
	2037	13.868	2037	13.868	2087	255.459
	2038	14.701	2038	14.701	2088	270.786
	2039	15.583	2039	15.583	2089	287.033
	2040	16.518	2040	16.518	2090	304.256
	2041	17.509	2041	17.509	2091	322.511
	2042	18.559	2042	18.559	2092	341.861
	2043	19.673	2043	19.673	2093	362.373
	2044	20.853	2044	20.853	2094	384.116
		50 Years				100 Years
Internal Rate of Return		11.53%				11.98%

Pennsylvania Power & Light Company
Common Stock Turnover Rates(1)
for Pennsylvania Power & Light Company and
the Barometer Group of Electric Companies
for the Years 1990-1994

	1990	1991	1992	1993	1994	Five Year Average
Pennsylvania Power & Light	3.40	4.93	4.17	4.23	2.58	3.86
Barometer Group of Eight Electric Companies						
Allegheny Power System	2.62	2.35	2.11	2.75	2.19	2.40
American Electric Power	2.59	2.63	2.82	2.70	2.07	2.56
Atlantic Energy Inc	2.54	2.45	2.21	3.12	2.22	2.51
Baltimore Gas & Electric	2.08	2.65	2.92	2.90	2.26	2.56
Delmarva Power & Light	2.61	2.54	2.83	2.83	2.21	2.60
Dpl Inc	2.52	2.22	2.59	3.01	2.52	2.57
Potomac Electric Power	2.33	2.38	2.53	3.13	1.77	2.43
Public Service Entrp	3.24	2.65	2.36	2.39	2.73	2.67
Average	2.57	2.48	2.55	2.85	2.25	2.54
High	3.24	2.65	2.92	3.13	2.73	2.67
Low	2.08	2.22	2.11	2.39	1.77	2.40

Note : (1) Common stock turnover rate is the year end common shares outstanding divided by the common shares traded.

Source of Information: OneSource
Standard & Poor's Utility Compustat

Schedule 5

Pennsylvania Power & Light Company
Relative Risk Analysis for
Pennslvania Power & Light Company, Witness Baudino's Group,
Witness Kahal's Group and Witness Moul's Group

	Time-liness Rank	Safety Rank	Beta	Financial Strength	Price Stability
Pennsylvania Power & Light Co.	4	2	0.65	B++	100
Allegheny Power System	3	1	0.65	A	100
American Electric Power Co.	3	3	0.75	B+	100
Atlantic Energy	3	2	0.70	A	100
Baltimore Gas & Electric Co.	3	2	0.80	B++	95
Carolina Power & Light Co.	4	2	0.80	A	95
Delmarva Power & Light Co.	3	2	0.65	A	100
Detroit Edison Co.	4	3	0.70	B+	100
Dominion Resources, Inc.	4	2	0.65	B++	100
DPL Inc.	4	2	0.60	A	100
IES Industries	3	2	0.60	A+	100
Kansas City Power & Light Co.	3	2	0.65	A	100
Midwest Resources, Inc.	3	3	0.50	B++	100
v England Electric System	4	2	0.75	A	100
..lahoma G & E Co.	3	2	0.70	A	95
Pacific G & E Co.	3	3	0.75	A	95
Potomac Electric Power Co.	4	1	0.75	A+	95
Public Service Enterprise Grp.	3	2	0.70	A	100
St Joseph Light & Power	3	2	0.50	A	95
San Diego G & E Co.	3	2	0.60	A+	95
SCANA Corp.	4	2	0.65	A	100
Southern Co.	4	1	0.65	A	100
Union Electric Co.	4	1	0.65	A+	100
Western Resources, Inc.	3	2	0.75	B++	95
Witness Baudino's Group	3.38	2.00	0.68	A	98.13
Witness Kahal's Group	3.44	2.06	0.67	A	98.75
Witness Moul's Group	3.25	1.88	0.70	A	98.75

Source of Information: Value Line Investment Survey, March 17, 1995, April 14, 19 and February 24, 1995

Exhibit PRM-3

PENNSYLVANIA POWER & LIGHT COMPANY

Schedules to Accompany

the Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Fair Rate of Return

I, *DIANE M. KOCH, Assistant Secretary of PP&L Resources, Inc., do* hereby CERTIFY that the following is a true and correct copy of certain resolutions duly adopted by the Board of Directors of the Company at a meeting held on April 26, 1995, and that said resolutions have not been altered, amended or repealed and are in full force and effect:

RESOLVED, That, subject to obtaining all requisite approvals, authorizations and consents, the proper officers of this Company are hereby authorized to arrange for the public issuance and sale of not in excess of 5.75 million additional shares of its authorized and unissued common stock, $.01 par value (the "Common Stock"), at such time and on such terms and conditions as may in their judgment be desirable, which shares when issued as hereinafter provided will be fully paid and nonassessable; and further

RESOLVED, That in connection with the issuance and sale by this Company of the Common Stock, the proper officers of this Company are hereby authorized to prepare, execute and file, on behalf of this Company:

(a) a Registration Statement, including a Prospectus, and any amendments or supplements thereto, including post-effective amendments, with the Securities and Exchange Commission ("SEC") registering said additional shares of Common Stock under the Securities Act of 1933;

(b) such other documents and instruments as may be necessary to qualify this Company or said additional shares of Common Stock under the Securities or Blue Sky Laws of such states of the United States and other jurisdictions as may be necessary or as may be required by the Underwriters of said additional shares of Common Stock, and to take further necessary action for said purposes;

(c) all necessary applications and other documents or agreements that may be required to list said shares of Common Stock on the New York and Philadelphia Stock Exchanges; and

(d) such other documents and instruments as may be necessary or, in their judgment, desirable to carry out the purposes of any or all of the resolutions adopted by the Board of Directors at this meeting relating to the proposed issuance and sale of said additional shares of Common Stock, and to take further necessary or desirable action;

and further

* * * * *

RESOLVED, That the initial public offering price per share for the Common Stock to be established by the pricing committee shall be set forth in an Underwriting Agreement to be entered into by the proper officers of this Company with a group of Underwriters, to be organized, jointly managed, and represented by Morgan Stanley & Co. Incorporated, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Prudential Securities Incorporated, after the effectiveness of this Company's Registration Statement, and shall be not less than $.50 under the reported last sale price (regular way) or the reported last asked price immediately prior to such determination of the initial public offering price, whichever is lower; and the Underwriters' discount to be established by the pricing committee shall be set forth in the Underwriting Agreement and shall be not in excess of 3.75% of the initial public offering price; and further

RESOLVED, That the proper officers of this Company are hereby authorized to negotiate and enter into the Underwriting Agreement with the Underwriters (substantially in the form presented to this meeting as Exhibit B, with such changes therein as may be approved by the proper officers of this Company), pursuant to which this Company shall (i) sell to the Underwriters not in excess of 5.75 million shares of the Common Stock, and the Underwriters shall promptly reoffer said shares to the public at an initial public offering price to be jointly agreed upon, and pursuant to which the purchase price to be paid by the Underwriters to this Company shall be equivalent to (a) the initial public offering price of said shares, less (b) the Underwriters' discount (together, the "purchase price"); and (ii) grant to the Underwriters an option, exercisable for not more than 30 days from the date of the initial public offering of the shares, to purchase at the purchase price up to 15% of said shares for their use to cover over-allotments; and further

RESOLVED, That the proper officers of this Company are hereby authorized to use the net proceeds from the issuance and sale of the Common Stock to make a capital contribution to Pennsylvania Power & Light Company.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the seal of the Company this 2nd day of May, 1995.

Diane M. Koch
Assistant Secretary

CS First Boston

CS First Boston Corporation

55 East 52nd Street
New York, NY 10055-0186
Telephone 212 909 2000

Trade Confirm

April 19, 1995

John R. Biggar
Vice President - Finance
Pennsylvania Power & Light Company

Via Facsimile

Dear John,

The following represents a confirmation for the repurchase transaction executed for PP&L this afternoon.

9 1/4% due 10/1/2019

Notional Amount:	$15MM
Reference Treasury Yield:	7.43%
Repurchase Spread:	113 bps.
Repurchase Yield:	8.56%
Repurchase Price:	107.009%
Price with Repurchase Fee:	107.259%
Principal Payment:	$16,088,850
25 Days Accrued Interest:	$96,354.17
Total Payment:	*$16,185,204.17*

9 3/8% due 7/1/2021

Notional Amount:	$29MM
Reference Treasury Yield:	7.43%
Repurchase Spread:	108 bps.
Repurchase Yield:	8.51%
Repurchase Price:	108.995%
Price with Repurchase Fee:	109.245%
Principal Payment:	$31,681,050
115 Days Accrued Interest:	$868,489.58
Total Payment:	*$32,549,539.58*

A grand total of $48,734,743.75 should be made available on the settlement day of April 26, 1995. If there are any questions regarding the transaction, please do not hesitate to call at (212) 909-4014.

Sincerely,

CS First Boston

Matthew Riez

cc. C. Chigas

CS FIRST BOSTON

CS First Boston Corporation

55 East 52nd Street
New York, NY 10055-0186
Telephone 212 909 2000

Trade Confirm

April 25, 1995

John R. Biggar
Vice President - Finance
Pennsylvania Power & Light Company

Via Facsimile

Dear John,

The following represents a confirmation for the repurchase transaction executed for PP&L this afternoon.

9 1/4% due 10/1/2019

Notional Amount:	$20MM
Reference Treasury Yield:	7.36%
Repurchase Spread:	113 bps.
Repurchase Yield:	8.49%
Repurchase Price:	107.762%
Price with Repurchase Fee:	108.012%
Principal Payment:	$21,602,400
31 Days Accrued Interest:	$159,305.56
Total Payment:	*$21,761,705.56*

9 3/8% due 7/1/2021

Notional Amount:	$5MM
Reference Treasury Yield:	7.36%
Repurchase Spread:	108 bps.
Repurchase Yield:	8.44%
Repurchase Price:	109.783%
Price with Repurchase Fee:	110.033%
Principal Payment:	$5,501,650
121 Days Accrued Interest:	$157,552.08
Total Payment:	*$5,659,202.08*

51160030.CTC

A grand total of $27,420,907.64 should be made available on the settlement day of May 2, 1995. If there are any questions regarding the transaction, please do not hesitate to call at (212) 909-4014.

Sincerely,

CS First Boston

Matthew Riez

cc. C. Chigas

CS FIRST BOSTON

CS First Boston Corporation

55 East 52nd Street
New York, NY 10055-0186
Telephone 212 909 2000

Trade Confirm

April 27, 1995

John R. Biggar
Vice President - Finance
Pennsylvania Power & Light Company

Via Facsimile

Dear John,

The following represents a confirmation for the repurchase transaction executed for PP&L this morning.

9 3/8% due 7/1/2021

Notional Amount:	$16.25MM
Reference Treasury Yield:	7.36%
Repurchase Spread:	110 bps.
Repurchase Yield:	8.46%
Repurchase Price:	109.556%
Price with Repurchase Fee:	109.806%
Principal Payment:	$17,843,475
123 Days Accrued Interest:	$520,507.81
Total Payment:	*$18,363,982.81*

A grand total of $18,363,982.81 should be made available on the settlement day of May 4, 1995. If there are any questions regarding the transaction, please do not hesitate to call at (212) 909-4014.

Sincerely,

CS First Boston

Matthew Riez

cc. C. Chigas

31170019.CTC

Transaction Summary

Amount Repurchased

9 1/4% due 10/1/2019	$35MM
9 3/8% due 7/1/2021	$50.25MM
Total Bonds Repurchased	***$85.25MM***

CS First Boston has currently closed all outstanding positions and offers made on behalf of Penn Power & Light while acting as agent.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 12-R1

R-943271 Hbg
5/23/95 TK

Supplemental Rebuttal Testimony of Paul R. Moul

Docket No. R-00943271

Q. Mr. Moul, have you previously submitted rebuttal testimony in this proceeding?

A. Yes. My rebuttal testimony identified as PP&L Statement 12-R, was submitted on May 5, 1995.

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

A. Pennsylvania Power & Light Company ("PP&L" or the "Company") has requested that I respond to a rate base adjustment proposed in the testimony of Mr. Thomas S. Catlin, a witness appearing on behalf of the Office of Consumer Advocate ("OCA").

Q. Have you reviewed OCA witness Catlin's proposal to reduce rate base to reflect deferred income taxes related to the Company's call premiums on high-cost long-term debt?

A. Yes. Mr. Catlin's rate base deduction for the deferred taxes on the call premiums should be rejected. Rate base deductions for deferred taxes are typically associated with rate base assets, such as the deferred taxes related to liberalized tax depreciation on plant in-service. In the case of the call premiums, there were <u>no</u> customer provided funds utilized to undertake the call of the Company's high cost debt but, instead, the call premium was an actual expenditure paid entirely with Company-provided funds. Moreover, the call of the Company's high-cost long-term debt occurred after the Company's last rate case and, since that time, the Company will have absorbed the portion of the call premiums that was amortized per books before that cost is reflected in customer rates in this case.

If the Company's claim in this case is approved, customers will begin to bear the cost of amortizing the remaining call premiums and will receive the benefit of the associated tax deduction in the Company's pro forma income tax expense calculation. The expense and the associated tax reductive effect will be matched. This occurs because, in calculating the appropriate pro forma interest expense deduction for ratemaking purposes, the "interest synchronization" technique is used. The deduction is calculated by applying the debt cost rate to the debt-funded portion of the allowed rate base. As discussed in my direct testimony, the amortization of the call premium is an element of the debt cost rate. Consequently, while customers will be charged for the call premiums over the term of the replacement debt issues, they will also be charged a lower amount of income taxes in the cost of service for the tax deductions created by these redemption costs. Hence, while the debt cost rate is higher by the amount to amortize the call premiums, income taxes are lower through higher tax deductions reflected in the embedded cost of debt. Mr. Catlin's approach, on the other hand, would give customers the benefit of the tax deduction up-front, in the form of a rate base reduction, before they have borne any costs associated with the call premiums.

Q. Is there another reason why Mr. Catlin's proposal is not proper?

A. In my opinion, the rate base deduction proposed by Mr. Catlin is also improper because it reduces the Company's net operating income at the overall rate of return (10.22% at the Company's proposed rates), despite the fact that the Company proposes to recover its call premiums at the much lower 7.97% embedded debt cost rate. OCA witness Catlin's proposal in this regard is simply wrong. Even if you accepted Mr. Catlin's premise, his proposed adjustment would remove more costs than the Company has claimed because the Company has not requested cost recovery at the overall rate of return.

Q. If Mr. Catlin's general approach were employed but the errors in its implementation were corrected, what would be the result?

A. For the reasons I previously explained, I do not believe that an adjustment for deferred income taxes is necessary or appropriate in this case. However, to recognize deferred income taxes related to the call of high cost debt would require a modification of the Company's capital structure ratios and embedded cost of debt. I have prepared Schedule 1 of Exhibit PRM-4 to show the change in the Company's capital structure ratios to reflect the impact of deferred income taxes related to the call premium. Recognizing the deferred tax provision, the Company's future test year end capital structure ratios become 46.96% long-term debt, 7.53% preferred stock, and 45.51% common equity. With the change in the long-term debt balance, the Company's future test year embedded cost of long-term debt becomes 7.84%. Reflecting the modified capital structure ratios and embedded debt cost rate, the Company's overall rate of return would become 10.15%. This is shown on Schedule 2 of Exhibit PRM-4.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes.

Exhibit PRM-4

PENNSYLVANIA POWER & LIGHT COMPANY

Schedules to Accompany

the Supplemental Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Fair Rate of Return

Pennslvania Power & Light Company
Capitalization and Capital Structure Ratios
Based upon Investor-Provided Capital
Actual on September 30, 1994 and Estimated at September 30, 1995

	Actual on September 30, 1994			Estimated at September 30, 1995		
		Ratios			Ratios	
	Amount Outstanding ($000's)	Including S-T Debt	Excluding S-T Debt	Amount Outstanding ($000's)	Including S-T Debt	Excluding S-T Debt
Long-Term Debt (1)						
First Mortgage Bonds	2,455,000			2,559,500 (3)		
Other Long-Term Debt	313,789			313,750 (4)		
Loss on Reaquired Debt	(115,273)			(115,887)		
ADIT on loss on Reaquired Debt	48,000 (E)			47,863		
Total Long-Term Debt	2,701,516	45.87%	47.58%	2,805,226	46.10%	46.96%
Preferred Stock						
Preferred Stock	466,375			466,375		
Unrecovered Call Premium	(21,338)			(16,840)		
Total Preferred Stock	445,037	7.56%	7.84%	449,535	7.39%	7.53%
Common Equity:						
Common Stock	1,413,855			1,598,327 (5)		
Retained Earnings (2)	1,117,454			1,120,366 (6)		
Total Common Equity	2,531,309	42.98%	44.58%	2,718,693	44.68%	45.51%
Total Permanent Capital	5,677,862			5,973,454		
Short-Term Debt	212,000	3.60%		111,703	1.84%	
Total Capital Employed	5,889,862	100.00%	100.00%	6,085,157	100.00%	100.00%

Notes: (1) Includes current portion of long-term debt.
(2) Adjusted to exclude the unamortized call premiums on reaquired preferred and preference stock previously charged to retained earnings.
(3) Reflects the issuance of $200,000,000 of 7.70% Series First Mortgage Bonds on October 1, 1994 and redemption of $95,500,000 of the 9 1/4% Series during the period June through August 1995.
(4) Reflects the redemption of $55,000,000 of 9 3/8% Series in June or July 1995, planned issuance of $55,000,000 of the Series K bonds, and repayment of $39,000 other long-term debt.
(5) Reflects Company estimate of Capital Stock which includes the planned issuance of about $78,000,000 through the Dividend Reinvestment Plan, about $7,000,000 through the Employee Stock Ownership Plan and $100,000,000 received from common stock issued by PP&L Resources.
(6) Reflects Company estimate of Retained Earnings.

Source of Information: Company provided data

Schedule 1

Pennsylvania Power & Light Co.
Cost of Capital and Fair Rate of Return
Estimated at September 30, 1995

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.96%	7.84%	3.68%
Preferred Stock	7.53%	7.31%	0.55%
Common Equity	45.51%	13.00%	5.92%
Overall Cost of Capital	100.00%		10.15%

Indicated level of fixed coverage assuming the Company could actually achieve a 10.15% overall rate of return.

Before-income tax coverage of interest expense based upon a 42.1435% effective federal and state income tax rate. (14.86% / 3.68%)	4.03x
After-income tax coverage of interest expense (10.15% / 3.68%)	2.75x
Overall coverage of interest expense and preferred stock dividends (10.15% / 4.23%)	2.40x

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 14-R R-943271 5/23/95

Rebuttal Testimony of Clyde D. Beers

Docket No. R-00943271

Q. Please state your name and business address.

A. Clyde D. Beers. Centre Square East, 1500 Market Street, Philadelphia PA 19102.

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

A. I am employed as a Principal of Towers Perrin, an actuarial and management consulting firm.

Q. Have you testified previously in this proceeding?

A. Yes. My direct testimony was previously admitted as PP&L Statement No. 14 and I was cross-examined at the hearing held on March 21, 1995.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Office of Consumer Advocate witness Thomas S. Catlin's recommended adjustments to the Company's claims for pension expense and other post-retirement benefit costs ("OPEBs").

Q. Please describe Mr. Catlin's recommended adjustments.

A. Mr. Catlin has proposed that PP&L's pension expense claim be rejected in its entirety and that its claim for current period OPEBs be reduced by $606,000 on a Pennsylvania jurisdictional basis. These recommendations are based on

Mr. Catlin's view that an 8.5% discount rate should have been utilized for purposes of calculating the Company's pension and OPEB claims in lieu of the 7.5% figure which was employed in the 1995 actuarial reports for those two items. Mr. Catlin also proposes that PP&L's requested amortization of deferred OPEB expense be denied. I understand that Mr. Bernini will address this latter adjustment in his rebuttal testimony.

Q. At page 15 of his testimony, Mr. Catlin compares bond yields at December 31, 1993 and December 31, 1994 and, on that basis, concludes that the data shown supports an increase in the discount rate utilized by PP&L in 1994 (7.0%) by 150 basis points, or to 8.5%. Do you agree?

A. No, I do not. Contrary to the impression left by Mr. Catlin, the selection of an appropriate discount rate is not a mechanical process tied to specific capital cost levels, but rather requires the exercise of informed judgment based on a careful review of multiple factors. In this regard, Statement of Financial Accounting Standards No. 87 ("SFAS 87") provides that "[a]ssumed discount rates shall reflect the rates at which the pension benefits could be effectively settled" (Paragraph No. 44). SFAS 87 then goes on to describe a range of interest rates that can be looked at to determine the rate that could be used to settle obligations. Statement of Financial Accounting Standards No. 106 ("SFAS 106"), which governs the accounting of OPEBs, is to the same effect.

Q. Has the Financial Accounting Standards Board (the "FASB") provided any additional guidance concerning the selection of a discount rate for actuarial purposes?

A. Yes. In a Special Report of Questions and Answers, the FASB stated as follows:

> The key is that the employer is using the rates implicit in current prices of annuity contracts as the basis to determine the best estimate of the effective settlement rates. The decision to use a particular methodology in a particular year does not mean that the employer must use that methodology in subsequent years. A change in the facts and circumstances may warrant the use of a different source that better reflects the rates at which the obligation could be effectively settled--currently.

Q. Have there been any recent developments which, in your view, have affected the rates at which obligations could be effectively settled?

A. Yes, there have. In prior years, insurers were willing to settle obligations at rates that exceeded long-term government bond yields. However, due to the well-publicized collapse of some insurers, the withdrawal of all but the highest-rated insurers from the market, and concern regarding future interest rates, I believe that a more reasonable expectation today is that pension obligations can be settled at rates 25 to 50 basis points below long-term government yields. Significantly, those rates stood at 7.9% as of January 1, 1995. Moreover, as noted by OCA witness Kahal, long-term yields had declined by approximately 50 basis points by mid-March. As such, the assumed 7.5% discount rate utilized by PP&L may, in fact, prove to be too high.

Q. Mr. Catlin also observes that, in recent rate proceeding, the Pennsylvania-American Water Company ("PAWC"), another client of Towers Perrin, updated its pension expense and OPEB claims to reflect the use of an 8.75% discount rate factor. Does the action taken by PAWC call into question the reasonableness of the 7.5% discount rate utilized by PP&L?

A. No, it does not. Indeed, I am aware of other clients which are currently utilizing discount rates less than the 7.5% figure employed by PP&L. More to the point, however, SFAS 87 and SFAS 106 clearly contemplate a range of acceptable rates for different companies and different pension and benefit plans. Indeed, FASB staff members have indicated in the past that the FASB could have developed a methodology which would produce a uniform discount rate for use by all plans but deliberately decided not to do so. As a result, the discount rate selected by PAWC is entirely irrelevant to the reasonableness of the 7.5% figure adopted by PP&L.

Q. Mr. Beers, would you please summarize your position with respect to Mr. Catlin's proposed adjustments?

A. In my opinion, PP&L's selection of a 7.5% discount rate for 1995 is consistent with the dictates of SFAS 87 and SFAS 106, is consistent with the current market for the settlement of obligations, is consistent with the Company's prior posture regarding discount rates and should, therefore, be appropriate and acceptable for ratemaking purposes. For these reasons, I believe that Mr. Catlin's proposed adjustments should be rejected.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

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PENNSYLVANIA POWER & LIGHT COMPANY

Statement 17-R

R-943271 ltsy
5/23/95

Rebuttal Testimony of John M. Chappelear

Docket No. R-00943271

Q. Please state your name and business address.

A. John M. Chappelear, Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") as Vice President-Investments & Pensions.

Q. What are your responsibilities in that position?

A. I am responsible for the Company's more than $1.0 billion in employee benefit funds, the Company's Nuclear Decommissioning Trust (NDT) funds, as well as other corporate investments.

Q. Please describe your education and employment background.

A. I graduated from Yale University with a bachelor of science degree in industrial engineering. I also attended the New York University Graduate School of Business.

I spent 18 years with Lehman Brothers Kuhn Loeb, where I was Executive Vice President and Director of the Investment Management Division. In 1978, I joined PP&L as Manager-Pension Fund Investments; in

1986, I was promoted to my present position. I am a member of the New York Society of Security Analysts, the Financial Executives Institute and the Committee on Investment of Employee Benefit Assets. I also am Chairman of the New York Stock Exchange Pension Managers Advisory Committee, and serve on the investment committees of several charitable funds.

Q. What is the purpose of your testimony?

A. My testimony responds to the proposals of OCA witness Kahal and PPLICA witness Kollen to increase the expected earnings rate on PP&L's NDT fund. These witnesses challenge the following three aspects of the Company's claim: (1) the Company's decision to initially invest 30% of the trust fund assets in common equities; (2) continued reliance, in part, on tax exempt bonds; and (3) the assumed return on the common equity portion of the investment. Based on these arguments, Messrs. Kahal and Kollen propose higher expected earnings rates on the trust fund. Mr. Kahal proposes an earnings rate of 7.5%. Mr. Kollen proposes to use the Company's proposed overall rate of return of 10.23%. In addition, Mr. Kollen proposes to require the Company to guarantee that the fund will earn the same overall return that PP&L claimed in this case, requiring the Company to bear all of the risks of the fund's performance.

Q. Do you agree with the proposals presented by these witnesses?

A. No, I do not. As explained below, their arguments are in error and should be rejected. More generally, their proposals are inconsistent and incomplete because they fail to consider the interrelationship between PP&L's proposed earnings rate on the NDT fund and the projected cost of decommissioning the Susquehanna plant.

The Company's decommissioning claim is driven by two fundamental factors: (1) the expected cost to decommission the plant at retirement; and (2) the expected funds available in the NDT account to pay for decommissioning at that time. To calculate the projected cost of decommissioning the plant, the Company estimated the cost of decommissioning in 1993 dollars and escalated that cost at a rate of inflation (4.0%) equal to the expected increase in the Consumer Price Index (CPI). To calculate the expected funds available in the NDT account, the Company assumed an after-tax earnings rate of 5.5% on trust fund assets. Both estimates are conservative. The Company might earn more than 5.5% on the trust fund, but the cost of decommissioning the plant will likely increase at more than the estimated 4.0% change in the CPI. As explained by Mr. LaGuardia, the types of costs generally involved in decommissioning, particularly radioactive waste disposal costs, have historically increased at a rate well in excess of the general rate of inflation. This conclusion was confirmed by me at a recent meeting of electric utilities with nuclear decommissioning trust funds. Based on presentations and discussions at that meeting, it is clear that PP&L's assumed 4.0% escalation in the cost of decommissioning the plant is well below the assumptions employed by other electric utilities.

If the opposing parties wish to employ more aggressive earnings assumptions, then they also should employ more realistic assessments of the future cost of decommissioning the plant. However, any increase in the inflation rate would more than offset the associated increase in the earnings rate. This occurs because the inflation rate is applied to the total current cost of decommissioning Susquehanna (approximately $723.8 million as of December 31, 1993) while the earnings rate is applied to the assets in the NDT fund (projected to be approximately $98.3 million as of September 30, 1995). For example, use of an annual 6% inflation rate in the cost of decommissioning (2 percentage points higher than the Company's 4% figure) and Mr. Kahal's recommended annual 7.5% earnings rate (again 2 percentage points above the Company's claim) would increase the Company's claim by $8.7 million in this case.

Q. Is the Company proposing to increase its claim?

A. No. My point simply is that the Company has employed conservative and interrelated assumptions on both sides of the equation. It is unfair and inconsistent for opposing parties to adjust only one side of the equation.

Q. Do you believe that the Company's plan to invest 30% of the trust fund in common equities is reasonable?

A. Yes, I do. The Company's primary goal is to assure that sufficient funds are available to decommission Susquehanna at its retirement. A cautious and risk adverse investment strategy is critical to achieving this result. A key consideration in this investment strategy is the fact that the plant must be decommissioned at a single point in time, not over an extended period, and that point in time might be substantially sooner than expected in the event of a premature decommissioning event. No matter when decommissioning occurs, the necessary funds must be available. This should be contrasted to the pension fund situation where the liability extends, with great certainty, over many years. As a result, PP&L can be somewhat more aggressive in its pension fund investments because payments from that fund are spread over many years. The Company's pension fund has maintained an equity exposure of 55%-66% since the

1960s, a strategy that is unopposed in this case, and which the Company expects to maintain in the future. In the case of the NDT fund, because the duration of its liability is shorter and less certain, I believe that a lesser equity exposure would be appropriate.

Q. Are there other reasons why the 30% figure is appropriate in this case?

A. Yes. Assuming that the Company's proposal to explicitly eliminate the "Black Lung" restrictions on its NDT fund investments is approved, the Company will begin to invest in common equities for the first time in late 1995 or 1996. It is a prudent and well-established investment strategy to implement major changes in asset allocation gradually in order to avoid the possibility of making major commitments at a market top and incurring substantial start-up losses. Such a conservative approach is particularly appropriate at this time because the stock market is trading at an all time high. The same approach will be used for beginning to scale out of equities, if possible, well before the decommissioning funds are needed. This process of ramping up the equity exposure at the outset, and scaling it down at the end, will certainly lead to a lower overall average exposure than the maximum achieved level. My best estimate is that the overall average equity exposure will approximate 30%.

Of course, depending on relative financial performance and market conditions, the Company may increase its equity investments more rapidly and/or reduce its exposure during the holding period.

Q. Do you believe the assumed earnings rate in equity investments in the NDT fund should be equal to the Company's claimed return on equity (ROE) in this proceeding?

A. No. This proposed adjustment is totally unreasonable and inappropriate. First, the Company's claimed ROE is a short-term figure designed to reflect investors' expected returns for the future test year and the initial period new rates will be in effect. The earnings rate on the NDT fund is a long-term figure intended to reflect the expected after-tax investment returns over the remaining life of the Susquehanna plant.

Second, the Company's claimed ROE in this proceeding is an opportunity rate of return which the Company may or may not achieve. It would be inappropriate to employ a short-term opportunity rate of return as an estimate of a long-term achieved return.

Finally, as explained above, the Company's expected return on equity investments in NDT fund assets is based on a 4% rate of inflation consistent with projected increases in the cost of decommissioning the plant. If a higher equity return is employed for an estimate of earnings on the trust fund, then the expected rate of inflation also must be increased. As explained above, this would increase the estimated cost of decommissioning the plant and would increase the cost of this item in the future test year.

Q. Does the Company's 5.5% estimated after-tax rate of return on NDT fund assets reflect the use of tax exempt bonds?

A. No, it does not. As Mr. Hill explained, during cross-examination, the Company's estimate was based upon an after-tax rate of return on long-term government bonds of 4.4% and an after-tax rate of return on long-tern corporate bonds of 4.8% (Tr. 420).

Q. Might it be appropriate for the Company to continue to invest a portion of the trust fund assets in tax exempt bonds?

A. Absolutely. The tax rate on the qualified portion of the trust fund is 22%, decreasing to 20% next year. The tax rate on the unqualified portion is equal to the marginal corporate income tax rate of 40%. The decision to invest in tax exempt bonds is determined by the rate spread between yields on taxable bonds and the tax exempt bonds. Since the NDT fund was created, the return on tax exempt bonds has ranged between 70% and 80% of the return on taxable U.S. Government bonds. Whenever tax exempt bonds yield more than 80% of U.S. Government bonds, the realized after-tax return on the tax exempt bonds will exceed the realized after-tax return on the U.S. Government bonds held in the qualified fund. When tax exempt rates exceed 60% of taxable rates, the realized after-tax return on tax exempt bonds will exceed taxable returns in the non-qualified funds. Under those circumstances, it is appropriate to invest in tax exempt bonds, and the Company will continue to do so.

Q. Please comment on Mr. Kollen's proposal that the Company be required to guarantee trust fund earnings at the same level as its allowed rate of return in this case.

A. Mr. Kollen's proposal should be rejected. The Company is not in a position to guarantee the future results of the stock and bond markets – nor is it appropriate to ask the Company to do so. While the Company can control the selection of its investments in the NDT fund, it has little or no control over the ultimate outcome of those investments. As recent experience has demonstrated, return on investments can vary dramatically for any number of reasons. For example, stock and bond markets are driven by inflation, interest rates and long-term economic trends. Similarly, NDT fund returns are stated on an after-tax basis and are affected by tax rates and other tax policy changes. PP&L has absolutely no control over any of these factors. In this context, Mr. Kollen's proposal is illogical; the results could be punitive; and it should be rejected.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

Exhibit DSH-4

R-943271 5/23/95
Hbg JK

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit to Accompany

the Rebuttal Testimony

of

Donald S. Hoch

Concerning

General Plant Account
Amortization

Account 3912

Amortization Calculation for Vintages as of 1995

Amortization Period = 20 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization
1975	484,950	0	484,950	19.5	472,826	7.959%	172,694	312,256	0.5	~~624,511~~ 312,256
1976	1,031,273	0	1,031,273	18.5	953,927	16.057%	348,411	682,862	1.5	455,241
1977	109,454	0	109,454	17.5	95,773	1.612%	34,980	74,475	2.5	29,790
1978	204,986	0	204,986	16.5	169,113	2.847%	61,767	143,219	3.5	40,920
1979	589,080	0	589,080	15.5	456,537	7.685%	166,745	422,335	4.5	93,852
1980	582,657	0	582,657	14.5	422,426	7.110%	154,286	428,370	5.5	77,886
1981	487,994	0	487,994	13.5	329,396	5.545%	120,308	367,686	6.5	56,567
1982	649,333	0	649,333	12.5	405,833	6.831%	148,226	501,107	7.5	66,814
1983	1,774,143	0	1,774,143	11.5	1,020,132	17.171%	372,591	1,401,552	8.5	164,888
1984	350,678	0	350,678	10.5	184,106	3.099%	67,243	283,436	9.5	29,835
1985	592,385	0	592,385	9.5	281,383	4.736%	102,772	489,613	10.5	46,630
1986	379,416	0	379,416	8.5	161,252	2.714%	58,895	320,521	11.5	27,871
1987	538,056	0	538,056	7.5	201,771	3.396%	73,694	464,361	12.5	37,149
1988	338,933	0	338,933	6.5	110,153	1.854%	40,232	298,701	13.5	22,126
1989	517,788	0	517,788	5.5	142,392	2.397%	52,007	465,781	14.5	32,123
1990	834,187	0	834,187	4.5	187,692	3.159%	68,552	765,635	15.5	49,396
1991	803,304	0	803,304	3.5	140,578	2.366%	51,345	751,960	16.5	45,573
1992	966,544	0	966,544	2.5	120,818	2.034%	44,127	922,416	17.5	52,709
1993	810,149	0	810,149	1.5	60,761	1.023%	22,192	787,957	18.5	42,592
1994		962,625	962,625	0.5	24,066	0.405%	8,790	953,836	19.5	48,915
1995	0	460,000	460,000	0.0	0	0.000%	0	460,000	20.0	23,000
	12,045,310		13,467,935		5,940,936	100.000%	2,169,858	11,298,078		~~2,068,390~~ 1,756,135

accrual for 1995 = 2,068,390

Retirements of pre-1975 plant= 2,842,364

Account 3914

Amortization Calculation for Vintages as of 1995

Amortization Period = 15 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization	
1980	68,049	0	68,049	14.5	65,781	8.849%	12,865	55,185	0.5	~~110,370~~	55,185
1981	117,394	0	117,394	13.5	105,655	14.213%	20,662	96,732	1.5	64,488	
1982	107,750	0	107,750	12.5	89,791	12.079%	17,560	90,190	2.5	36,076	
1983	108,048	0	108,048	11.5	82,837	11.143%	16,200	91,848	3.5	26,242	
1984	96,256	0	96,256	10.5	67,379	9.064%	13,177	83,079	4.5	18,462	
1985	123,342	0	123,342	9.5	78,117	10.508%	15,277	108,065	5.5	19,648	
1986	114,090	0	114,090	8.5	64,651	8.697%	12,644	101,446	6.5	15,607	
1987	70,200	0	70,200	7.5	35,100	4.722%	6,864	63,336	7.5	8,445	
1988	107,228	0	107,228	6.5	46,466	6.251%	9,087	98,141	8.5	11,546	
1989	75,169	0	75,169	5.5	27,562	3.708%	5,390	69,779	9.5	7,345	
1990	83,690	0	83,690	4.5	25,107	3.377%	4,910	78,779	10.5	7,503	
1991	105,283	0	105,283	3.5	24,566	3.305%	4,804	100,479	11.5	8,737	
1992	116,677	0	116,677	2.5	19,446	2.616%	3,803	112,874	12.5	9,030	
1993	101,812	0	101,812	1.5	10,181	1.370%	1,991	99,821	13.5	7,394	
1994		22,119	22,119	0.5	737	0.099%	144	21,975	14.5	1,515	
1995	0	0	0	0.0	0	0.000%	0	0	15	0	
	1,394,989		1,417,108		743,376	100.000%	145,379	1,271,729		~~352,409~~	297,224

accrual for 1995 = 352,409

Retirements of pre-1980 plant= 800,974

Account 3916

Amortization Calculation for Vintages as of 1995

Amortization Period = 10 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization	
1985	103,437	0	103,437	9.5	98,265	13.894%	107,177	(3,740)	0.5	~~(7,481)~~	(3,740)
1986	7,015	0	7,015	8.5	5,963	0.843%	6,504	511	1.5	341	
1987	72,745	0	72,745	7.5	54,559	7.714%	59,507	13,238	2.5	5,295	
1988	93,564	0	93,564	6.5	60,816	8.599%	66,332	27,232	3.5	7,780	
1989	34,161	0	34,161	5.5	18,788	2.657%	20,493	13,668	4.5	3,037	
1990	132,264	0	132,264	4.5	59,519	8.416%	64,917	67,347	5.5	12,245	
1991	112,100	0	112,100	3.5	39,235	5.548%	42,793	69,307	6.5	10,663	
1992	1,474,163	0	1,474,163	2.5	368,541	52.110%	401,966	1,072,197	7.5	142,960	
1993	10,297	0	10,297	1.5	1,545	0.218%	1,685	8,612	8.5	1,013	
1994		132,435	132,435	0.5	0	0.000%	0	132,435	9.5	13,941	
1995	0	0	0	0.0	0	0.000%	0	0	10	0	
	2,039,745		2,172,180		707,230	100.000%	771,373	1,400,807		~~189,794~~	193,534

accrual for 1995 = 189,794

Retirements of pre-1985 plant= 149,120

Account 3930

Amortization Calculation for Vintages as of 1995

Amortization Period = 30 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization
1965	6,105	0	6,105	29.5	6,004	0.557%	5,419	687	0.5	~~1,374~~ 627
1966	5,958	0	5,958	28.5	5,660	0.525%	5,109	849	1.5	566
1967	11,738	0	11,738	27.5	10,760	0.998%	9,712	2,027	2.5	811
1968	22,181	0	22,181	26.5	19,593	1.818%	17,684	4,497	3.5	1,285
1969	33,585	0	33,585	25.5	28,547	2.648%	25,765	7,819	4.5	1,738
1970	60,191	0	60,191	24.5	49,156	4.560%	44,366	15,825	5.5	2,877
1971	78,279	0	78,279	23.5	61,319	5.689%	55,344	22,935	6.5	3,529
1972	144,828	0	144,828	22.5	108,621	10.077%	98,037	46,791	7.5	6,239
1973	100,355	0	100,355	21.5	71,921	6.672%	64,913	35,442	8.5	4,170
1974	76,924	0	76,924	20.5	52,565	4.876%	47,443	29,481	9.5	3,103
1975	278,612	0	278,612	19.5	181,098	16.801%	163,451	115,161	10.5	10,968
1976	7,741	0	7,741	18.5	4,774	0.443%	4,309	3,433	11.5	298
1977	5,893	0	5,893	17.5	3,438	0.319%	3,103	2,790	12.5	223
1978	108,818	0	108,818	16.5	59,850	5.552%	54,018	54,800	13.5	4,059
1979	208,505	0	208,505	15.5	107,727	9.994%	97,230	111,274	14.5	7,674
1980	11,064	0	11,064	14.5	5,348	0.496%	4,827	6,238	15.5	402
1981	58,793	0	58,793	13.5	26,457	2.454%	23,879	34,914	16.5	2,116
1982	212,547	0	212,547	12.5	88,561	8.216%	79,932	132,616	17.5	7,578
1983	164,258	0	164,258	11.5	62,965	5.841%	56,830	107,428	18.5	5,807
1984	28,767	0	28,767	10.5	10,068	0.934%	9,087	19,680	19.5	1,009
1985	218,031	0	218,031	9.5	69,043	6.405%	62,316	155,716	20.5	7.596
1986	11,557	0	11,557	8.5	3,275	0.304%	2,956	8,602	21.5	400
1987	116,207	0	116,207	7.5	29,052	2.695%	26,221	89,986	22.5	3,999
1988	21,109	0	21,109	6.5	4,574	0.424%	4,128	16,981	23.5	723
1989	17,278	0	17,278	5.5	3,168	0.294%	2,859	14,419	24.5	589
1990	2,250	0	2,250	4.5	338	0.031%	305	1,945	25.5	76
1991	9,505	0	9,505	3.5	1,109	0.103%	1,001	8,504	26.5	321

1992	9,313	0	9,313	2.5	776	0.072%	700	8,612	27.5	313	
1993	40,387	0	40,387	1.5	2,019	0.187%	1,823	38,564	28.5	1,353	
1994		8,620	8,620	0.5	144	0.013%	130	8,490	29.5	288	
1995	0	0	0	0.0	0	0.000%	0	0	30	0	
	2,070,780		2,079,400		1,077,929	100.000%	972,893	1,106,507		~~81,484~~	80,797

accrual for 1995 = 81,484

Retirements of pre-1965 plant= 74,866

Account 3946

Amortization Calculation for Vintages as of 1995

Amortization Period = 20 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization	
1975	61,675	0	61,675	19.5	60,133	5.341%	2,048	59,626	0.5	~~119,252~~	59,626
1976	55,037	0	55,037	18.5	50,910	4.522%	1,734	53,303	1.5	35,535	
1977	52,655	0	52,655	17.5	46,073	4.092%	1,569	51,086	2.5	20,434	
1978	97,745	0	97,745	16.5	80,640	7.162%	2,747	94,998	3.5	27,142	
1979	116,634	0	116,634	15.5	90,391	8.028%	3,079	113,554	4.5	25,234	
1980	66,849	0	66,849	14.5	48,466	4.305%	1,651	65,198	5.5	11,854	
1981	78,696	0	78,696	13.5	53,120	4.718%	1,810	76,887	6.5	11,829	
1982	193,275	0	193,275	12.5	120,797	10.729%	4,115	189,160	7.5	25,221	
1983	149,046	0	149,046	11.5	85,702	7.612%	2,919	146,127	8.5	17,191	
1984	83,385	0	83,385	10.5	43,777	3.888%	1,491	81,893	9.5	8,620	
1985	165,133	0	165,133	9.5	78,438	6.967%	2,672	162,461	10.5	15,473	
1986	169,759	0	169,759	8.5	72,148	6.408%	2,458	167,302	11.5	14,548	
1987	213,907	0	213,907	7.5	80,215	7.125%	2,733	211,175	12.5	16,894	
1988	300,980	0	300,980	6.5	97,819	8.688%	3,332	297,648	13.5	22,048	
1989	97,219	0	97,219	5.5	26,735	2.375%	911	96,308	14.5	6,642	
1990	79,606	0	79,606	4.5	17,911	1.591%	610	78,996	15.5	5,097	
1991	124,037	0	124,037	3.5	21,707	1.928%	739	123,298	16.5	7,473	
1992	346,192	0	346,192	2.5	43,274	3.844%	1,474	344,718	17.5	19,698	
1993	77,242	0	77,242	1.5	5,793	0.515%	197	77,045	18.5	4,165	
1994		73,459	73,459	0.5	1,836	0.163%	63	73,397	19.5	3,764	
1995	0	121,000	121,000	0.0	0	0.000%	0	121,000	20	6,050	
	2,529,074		2,723,534		1,125,884	100.000%	38,353	2,685,180		~~424,165~~	364,539

accrual for 1995 = 424,165

Retirements of pre-1975 plant= 773,211

Account 3950

Amortization Calculation for Vintages as of 1995

Amortization Period = 15 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization
1980	77,502	0	77,502	14.5	74,918	3.815%	(604)	78,106	0.5	~~156,211~~ 78,106
1981	199,596	0	199,596	13.5	179,636	9.147%	(1,448)	201,044	1.5	134,029
1982	228,885	0	228,885	12.5	190,738	9.713%	(1,538)	230,423	2.5	92,169
1983	130,347	0	130,347	11.5	99,933	5.089%	(806)	131,153	3.5	37,472
1984	616,749	0	616,749	10.5	431,725	21.984%	(3,480)	620,230	4.5	137,829
1985	506,435	0	506,435	9.5	320,742	16.333%	(2,586)	509,020	5.5	92,549
1986	316,710	0	316,710	8.5	179,469	9.139%	(1,447)	318,157	6.5	48,947
1987	236,157	0	236,157	7.5	118,079	6.013%	(952)	237,109	7.5	31,615
1988	348,067	0	348,067	6.5	150,829	7.680%	(1,216)	349,283	8.5	41,092
1989	183,177	0	183,177	5.5	67,165	3.420%	(541)	183,718	9.5	19,339
1990	320,134	0	320,134	4.5	96,040	4.891%	(774)	320,908	10.5	30,563
1991	125,030	0	125,030	3.5	29,174	1.486%	(235)	125,265	11.5	10,893
1992	49,229	0	49,229	2.5	8,205	0.418%	(66)	49,295	12.5	3,944
1993	166,074	0	166,074	1.5	16,607	0.846%	(134)	166,208	13.5	12,312
1994		16,186	16,186	0.5	540	0.027%	(4)	16,191	14.5	1,117
1995	0		0	0.0	0	0.000%	0	0	15	0
	3,504,091		3,520,277		1,963,798	100.000%	(15,832)	3,536,109		~~850,080~~ 771,974

accrual for 1995 = 850,080

Retirements of pre-1980 plant= 1,008,417

Account 3980
Amortization Calculation for Vintages as of 1995
Amortization Period = 25 years

	Plant at 1/1/94	1994/5 Activity	Plant at 12/31/95	Age at 1/1/95	Calculated Reserve	Reserve Allocation	Allocated Book Reserve	Net Plant	Remaining Life	Amortization	
1970	76,058	0	76,058	24.5	74,537	4.519%	37,259	38,799	0.5	~~77,598~~	38,799
1971	467,240	0	467,240	23.5	439,206	26.629%	219,548	247,692	1.5	165,128	
1972	58,559	0	58,559	22.5	52,703	3.195%	26,345	32,214	2.5	12,886	
1973	65,954	0	65,954	21.5	56,721	3.439%	28,353	37,601	3.5	10,743	
1974	59,756	0	59,756	20.5	49,000	2.971%	24,494	35,262	4.5	7,836	
1975	99,329	0	99,329	19.5	77,477	4.697%	38,729	60,600	5.5	11,018	
1976	101,035	0	101,035	18.5	74,766	4.533%	37,374	63,661	6.5	9,794	
1977	107,694	0	107,694	17.5	75,386	4.571%	37,684	70,011	7.5	9,335	
1978	37,718	0	37,718	16.5	24,894	1.509%	12,444	25,274	8.5	2,973	
1979	121,571	0	121,571	15.5	75,374	4.570%	37,678	83,893	9.5	8,831	
1980	79,661	0	79,661	14.5	46,203	2.801%	23,096	56,565	10.5	5,387	
1981	279,077	0	279,077	13.5	150,701	9.137%	75,332	203,745	11.5	17,717	
1982	42,532	0	42,532	12.5	21,266	1.289%	10,630	31,902	12.5	2,552	
1983	154,940	0	154,940	11.5	71,273	4.321%	35,627	119,313	13.5	8,838	
1984	137,670	0	137,670	10.5	57,821	3.506%	28,903	108,766	14.5	7,501	
1985	155,159	0	155,159	9.5	58,961	3.575%	29,473	125,686	15.5	8,109	
1986	126,513	0	126,513	8.5	43,015	2.608%	21,502	105,011	16.5	6,364	
1987	258,798	0	258,798	7.5	77,639	4.707%	38,810	219,988	17.5	12,571	
1988	68,966	0	68,966	6.5	17,931	1.087%	8,963	60,002	18.5	3,243	
1989	197,483	0	197,483	5.5	43,446	2.634%	21,718	175,765	19.5	9,014	
1990	152,680	0	152,680	4.5	27,482	1.666%	13,738	138,942	20.5	6,778	
1991	42,077	0	42,077	3.5	5,891	0.357%	2,945	39,132	21.5	1,820	
1992	218,313	0	218,313	2.5	21,831	1.324%	10,913	207,400	22.5	9,218	
1993	90,032	0	90,032	1.5	5,402	0.328%	2,700	87,332	23.5	3,716	
1994		20,444	20,444	0.5	409	0.025%	204	20,240	24.5	826	
1995	0	0	0	0.0	0	0.000%	0	0	25	0	
	3,198,816		3,219,260		1,649,335	100.000%	824,461	2,394,799		~~419,796~~	380,997

accrual for 1995 = 419,796
Retirements of pre-1970 plant= 156,512

OTS Statement No. SR-1 OTS Exh SR-1
Witness: K. L. Deardorff
Date: May 17, 1995

R-943271 Hbg
5/23/95 TK

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

Pennsylvania Power & Light Company

Docket No. R-00943271

Surrebuttal Testimony

of

Kevan L. Deardorff

Concerning:

Fair Rate of Return

BA

Q. Have you testified previously in this proceeding?

A. Yes, I have. Please refer to OTS Statement No. 1 and OTS Exhibit No. 1.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Mr. Paul Moul as it impacts on the rate of return position set forth in my direct testimony.

Q. Mr. Moul stated that "during the past five months, long-term interest rates have declined about one-half percentage point (i.e., 0.50%) using long-term Treasury bond yields as a benchmark." Is this a factual statement?

A. No. The information provided in OTS Surrebuttal Exhibit 1, Schedule No. 1, indicates that the 30-year Treasury bond yield peaked during the week ending November 11, 1994 at about 8.16 percent. The 30-year Treasury bond yield when Mr. Moul filed his rebuttal testimony was 7.02 percent. Therefore, the 30-year Treasury bond yield has declined by 114 basis points.

Q. On page 2 of his rebuttal testimony, Mr. Moul indicated that this decline in interest rates does not require a reduction in his recommended cost of equity. Is this consistent with his past testimony before the Commission?

A. No. In the most recent Philadelphia Suburban Water Company rate case (R-00932868), Mr. Moul encountered a similar situation. Thirty-year Treasury bond yields increased 110 basis points resulting in the Risk Premium cost rates increasing 75 basis points, the CAPM cost rates increasing 106 basis points, and the DCF cost rates increasing 19 basis points. Mr. Moul found it appropriate to increase his recommended cost of equity because of the significant increase in interest rates.

Q. On page 6 of his rebuttal testimony, Mr. Moul attempted to show the inadequacy of your recommendation by calculating a growth rate using the internal growth rate method. What problem do you have with Mr. Moul's testimony regarding internal growth rates?

A. Mr. Moul originally testified that this methodology does not produce results reflective of investor expected growth (PP&L Statement 12, page c-15). It is contradictory for him to choose this method in order to discredit my recommended return on equity.

Q. On page 18 of his rebuttal testimony, Mr. Moul suggests that all models that do not recognize all factors that influence investor expectations should be avoided when setting the rate of return on common equity. Is this a critical factor in determining which model will give superior results?

A. Yes. The DCF model is based on expectations of equity investors which are influenced by all qualitative and quantitative market factors. These market factors include the developing risk factors which will impact the electric utility industry and PP&L. The other three methods (Risk Premium, CAPM, and Comparable Earnings) that Mr. Moul has presented are based on historical relationships, therefore no account has been taken of these market factors in the results produced by those models. Clearly, the DCF method is superior based on this criteria.

Q. Mr. Moul states that you made the unfounded assertion that while the Risk Premium and CAPM models are relevant to investors, that relevancy does not carry over to the ratesetting process. Is this assertion unfounded?

A. No. The relevancy of historical risk premiums in determining expected returns has been challenged repeatedly in financial journals. For example, William Gray published an article in the Journal of Portfolio Management (Fall, 1989) entitled "The Anatomy of a Stock Market Forecast". In this article Mr. Gray gives two reasons for rejecting the use of risk premiums:

(1) At any given time, the true (forward-looking) risk premium for any riskier asset class may be quite different from what is indicated by historical relationships, i.e., the spread between any longer-term average returns of that particular asset class and that of any less risky asset class with which it is compared.

(2) Even if the current risk premium happens to be specified properly by the historical spread between two classes, it may be a long time before it is approximated in the ensuing experience of holding-period returns.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

FEDERAL RESERVE statistical release

These data are released each Monday. The availability of the release is announced on (202) 452-3206.

H.15 (519)

SELECTED INTEREST RATES

Yields in percent per annum

For immediate release
November 14, 1994

Instruments	1994 Nov 7	1994 Nov 8	1994 Nov 9	1994 Nov 10	1994 Nov 11 *	Week Ending Nov 11	Week Ending Nov 4	1994 Oct
Federal funds (effective) [1,2,3]	4.69	4.51	5.28	4.99	4.99	4.74	4.77	4.76
Commercial paper [3,4,5]								
1-month	5.22	5.24	5.24	5.27		5.24	5.05	5.02
3-month	5.73	5.73	5.73	5.75		5.74	5.63	5.51
6-month	5.92	5.94	5.94	5.95		5.94	5.82	5.70
Finance paper placed directly [3,4,6]								
1-month	5.15	5.15	5.15	5.18		5.16	4.96	4.91
3-month	5.58	5.58	5.59	5.61		5.59	5.47	5.36
6-month	5.41	5.41	5.41	5.43		5.42	5.32	5.30
Bankers acceptances (top rated) [3,4,7]								
3-month	5.65	5.65	5.62	5.60		5.63	5.52	5.41
6-month	5.85	5.85	5.80	5.80		5.83	5.73	5.59
CDs (secondary market) [3,8]								
1-month	5.19	5.21	5.21	5.21		5.21	5.04	4.98
3-month	5.72	5.73	5.72	5.71		5.72	5.59	5.51
6-month	6.02	6.02	6.01	6.01		6.02	5.92	5.79
Eurodollar deposits (London) [3,9]								
1-month	5.19	5.19	5.19	5.25		5.20	5.00	4.96
3-month	5.69	5.75	5.75	5.75		5.73	5.56	5.52
6-month	6.00	6.06	6.06	6.03		6.04	5.88	5.77
Bank prime loan [2,3,10]	7.75	7.75	7.75	7.75	7.75	7.75	7.75	7.75
Discount window borrowing [2,11]	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
U.S. government securities								
Treasury bills								
Auction average [3,4,12]								
3-month	5.25					5.25	5.07	4.96
6-month	5.68					5.68	5.51	5.39
1-year				6.09				5.72
Auction average (investment) [13]								
3-month	5.39					5.39	5.21	5.09
6-month	5.93					5.93	5.75	5.63
1-year				6.48		6.48		6.06
Secondary market [3,4]								
3-month	5.22	5.23	5.20	5.23		5.22	5.10	4.95
6-month	5.65	5.65	5.62	5.64		5.64	5.53	5.39
1-year	6.02	5.99	5.97	6.01		6.00	5.90	5.75
Treasury constant maturities [14]								
1-year	6.42	6.39	6.37	6.50		6.42	6.28	6.11
2-year	7.06	7.02	7.01	7.06		7.04	6.95	6.73
3-year	7.39	7.39	7.35	7.40		7.38	7.24	7.04
5-year	7.73	7.69	7.64	7.69		7.69	7.61	7.40
7-year	7.89	7.85	7.79	7.84		7.84	7.77	7.58
10-year	8.05	8.01	7.94	7.98		8.00	7.94	7.74
20-year	8.30	8.24	8.21	8.27		8.26	8.21	8.08
30-year	8.16	8.12	8.09	8.15		8.13	8.08	7.94
Composite								
Over 10 years (long-term) [15]	8.25	8.21	8.16	8.22		8.21	8.16	8.02
Corporate bonds								
Moody's seasoned								
Aaa	8.79	8.74	8.69	8.74	8.74	8.74	8.68	8.57
Baa	9.42	9.37	9.32	9.37	9.37	9.37	9.32	9.20
A-utility [16]					9.00	9.00	9.05	8.80
State & local bonds [17]				6.96		6.96	6.83	6.52
Conventional mortgages [18]					9.19	9.19	9.05	8.93

See overleaf for footnotes
* Markets closed

OCA STATEMENT NO. 1A

R-943271 5/23/95
Hbg

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
FAIR RATE OF RETURN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

THE SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
FAIR RATE OF RETURN

I. OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. My business address is 12510 Prosperity Drive, Silver Spring, Maryland 20904. I am a Senior Economist and Principal at Exeter Associates, Inc., a consulting firm specializing in public utility regulation and energy studies. I have held that position since January 1981.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I have. In early April 1995, I submitted direct testimony on behalf of the Office of Consumer Advocate (OCA) on the subject of fair rate of return to be applied to the Pennsylvania jurisdictional rate base of Pennsylvania Power & Light Company (PP&L). That testimony also addressed the expected earnings on nuclear decommissioning trust funds. At the same time I submitted separate testimony concerning the generation capacity issues in this case. (OCA Statement No. 2) A statement of my qualifications and listing of past testimony accompanied my direct testimony filed in April.

Q. WHAT RATE OF RETURN DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY?

A. I recommended an overall return of 9.33 percent including 11.1 percent on the common equity component. This compares to 10.22 percent overall and 13.0 percent recommended by Mr. Moul on behalf of PP&L.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to the rebuttal testimony of Mr. Moul concerning cost of equity evidence and capital structure, and it also provides updated information on capital cost trends. I will separately respond to the PP&L rebuttal testimony on capacity issues in OCA Statement No. 2A.

Q. HOW HAVE YOU CONDUCTED YOUR UPDATE?

A. My original DCF cost of equity studies were based upon market data extending through February 1995, i.e., September 1994-February 1995 averages. I have been able to update through April 1995, and I have recalculated dividend yields accordingly for the two proxy groups and for PP&L on a stand-alone basis. In addition, in my update I have eliminated two of the original 17 companies from my primary proxy group (Union Electric and Southern Company) since those two companies are rated "1" for Safety. My selection criteria include only those electric utilities rated "2" or "3" for Safety by the Value Line Investment Survey. These two exclusions have the effect of slightly increasing the group average dividend yields.

My updating of the six-month average dividend yields indicates virtually no change in the group averages compared to the figures in my original testimony.

Consequently, I continue to recommend an 11.1 percent return on common equity for PP&L. The updated dividend yields are shown on Schedule MIK-4, pages 1 and 2, May 1995 update. I also provide a revised Schedule MIK-6, pages 1-6, for my primary proxy group in order to restate the growth rate evidence after deleting Union Electric and Southern Company. This exclusion results in a very slight decline in the growth rate measures, but the decline is too small to warrant a change to my cost of equity estimate for this group.

Q. HAVE YOU UPDATED YOUR CAPITAL COST INDICATORS?

A. Yes. I have updated my original Schedule MIK-2 so that it extends through April 1995. As this schedule indicates, long-term interest rates have moderated significantly since year-end 1994. Despite the widely publicized problems in foreign exchange markets, conditions in capital markets so far this year have shown considerable improvement. This improvement appears to be based on the view that economic activity is slowing and inflation remains moderate.

A clear indication of slowing economic activity was the increase in the nation-wide unemployment rate announced in May from 7.5 to 7.8 percent. In response to the slowdown, the 30-year Treasury bond yield has fallen back to 7.0 percent by mid-May compared to over 8 percent in late 1994.

Q. IN YOUR DIRECT TESTIMONY, YOU PROVIDED PROJECTIONS FROM <u>BLUE CHIP ECONOMIC INDICATORS</u>. HAVE THOSE PROJECTIONS CHANGED?

A. They have declined modestly. In my direct testimony, I presented the March 1995 "consensus" near-term and long-term projections. Blue Chip will publish its next set of long-term projections in October. However, Blue Chip published new near-term projections on May 10, which indicate a small improvement in capital costs (i.e., a lowering) compared to the March 1995 projections which I cited in my direct testimony. The May 10, 1995 projections for 1995 and 1996 are as follows:

Blue Chip "Consensus" Projections[1]

	1995	1996
Inflation (CPI)	3.2%	3.6%
Aaa Corporate Bonds	8.2	8.1
3-Month T-Bills	6.0	6.0

[1]May 10, 1995 Update.

The May projections of Aaa corporate bond yields for 1995 and 1996 are about 0.2 percentage points lower than the March figures for those two years cited in my direct testimony.

II. REPLY TO MR. MOUL'S REBUTTAL TESTIMONY

Overview

Q. WHAT ARE THE MAIN ARGUMENTS RAISED BY MR. MOUL IN HIS REBUTTAL TESTIMONY?

A. Most of Mr. Moul's rebuttal testimony concerns the cost of and fair return on common equity, but he also briefly addresses capital structure. In response to Mr. Baudino, he argues that the proposed capital structure is appropriate, and in response to me, he defends his adjustment to reduce PP&L's debt balance, i.e., removal of $116 million of losses on reacquisition for capital structure purposes.

With respect to return on equity, he argues that my 11.1 percent and the recommended figures of other non-PP&L witness will not be acceptable to the financial community. According to Mr. Moul, these recommendations fail to provide a reasonable premium over single A utility bond yields, nor do they provide PP&L with a meaningful retained earnings "cushion" over its current per share dividend level. In addition, he argues that the ROE recommendations of the opposing parties are unreasonable because, if approved, they would not provide PP&L with the dividend growth that I (and other witnesses) assumed for PP&L in our respective DCF studies.

Mr. Moul also discusses the technical and methodological aspects of the various cost of equity studies. Citing a NARUC survey, he concludes that utility commissions base their ROE decisions on both DCF studies and non-DCF methods. He criticizes my reliance on the DCF method as the sole basis for my recommendations.

Q. ASIDE FROM YOUR RELIANCE ON THE DCF, DOES MR. MOUL DISPUTE YOUR DCF CALCULATIONS?

A. Aside from his general distrust of the model, he disputes only one aspect of my DCF studies. He indicates a disagreement with my use of earnings retention calculations as an estimate of the DCF growth rate. He expresses no serious disagreement with any other aspect of my DCF studies.

Q. DOES MR. MOUL ADDRESS OTHER COST OF EQUITY METHODS?

A. Yes, but only very briefly. He criticizes my risk premium study for relying on historic FERC-benchmark rates of return, and he defends his estimate of the 16 percent stock market rate of return used in his CAPM study.

Q. DOES ANY OF THE EVIDENCE OR ARGUMENTS PRESENTED BY MR. MOUL IN HIS REBUTTAL TESTIMONY CAUSE YOU TO ALTER YOUR POSITION ON FAIR RATE OF RETURN?

A. No. Mr. Moul's rebuttal testimony contains a number of conceptual errors and is not supported by available evidence. In addition, Mr. Moul did not respond in any meaningful way to my criticisms of his original cost of equity studies.

Capital Structure

Q. MR. MOUL DEFENDS HIS ADJUSTMENT TO SUBTRACT $116 MILLION FROM THE BALANCE OF LONG-TERM DEBT FOR CAPITAL STRUCTURE PURPOSES. HOW DOES HE RESPOND TO YOUR APPROACH TO THIS ISSUE?

A. Mr. Moul argues that his capital structure adjustment is "necessary to fully recover the cost of redeeming high cost debt" ... and that my approach "unfairly lowers the Company's equity ratio. ..." (Statement 12-R, page 8)

Essentially, his argument is that when PP&L refinanced its high cost debt (and incurred "losses") doing so had the effect of "skewing" PP&L's capital structure. His debt balance adjustment serves to offset the alleged distortion. He cites a 1990 National Fuel Gas Distribution (NFGD) order as precedent for this adjustment.

Q. DOES YOUR TREATMENT FAIL TO PROVIDE PP&L WITH FULL COST RECOVERY FOR LOSSES ON REACQUISITION?

A. No. I provide PP&L with total recovery of those costs (through an amortization) <u>plus</u> a debt return on the unamortized balance of those reacquisition expenses. Doing so raises the embedded cost of debt from 7.40 to 7.97 percent and adds about $16 million to PP&L's cost of service (total company). Mr. Moul's capital structure adjustment adds an <u>additional</u> $8 million, for a total of $24 million. I did not set cost recovery at $16 million merely because it happens to be lower than $24 million. I favor the $16 million (reflected in the 7.97 percent debt cost rate) because that amount provides PP&L with full cost recovery.

Contrary to the impression in Mr. Moul's testimony, I am <u>not</u> lowering PP&L's equity ratio. Rather, I propose to use in this case PP&L's projected <u>actual</u> capital structure ratios at 9/30/95. It is Mr. Moul who seeks to alter the actual, per books capital structure ratios. This is an adjustment which investor analysts (e.g., credit rating agencies) do not make.

Q. DOES DEBT REACQUISITION "SKEW" THE CAPITAL STRUCTURE RATIOS?

A. No. PP&L incurred debt reacquisition costs over a period of years in order to lower its cost of debt. Those expenses were financed with whatever mix of capital the Company chose to use at the various times that the reacquisitions occurred. Unlike a typical expense, however, the reacquisition costs were booked by PP&L as a "regulatory asset" to be recovered in future rates and therefore they contribute to the Company's common equity balance. Thus, no reduction to common equity occurred from the losses on reacquisition, except as amortization takes place. However, since annual interest expense savings from refinancings greatly exceeds the annual amortization, the probable net effect is an <u>increase</u> in PP&L's common equity. This increase to profits and hence equity could take place because PP&L has not had a rate case during the intervening period, and therefore the net interest expense savings (i.e., net of the amortizations) have flowed 100 percent to shareholders. From this perspective, an adjustment to even <u>further</u> increase the equity ratio above its actual level -- as Mr. Moul argues -- makes no sense.

Mr. Moul's argument that capital structure has been "skewed" is unpersuasive on the most fundamental level because <u>PP&L management controls capital structure</u>. Actual capital structure ultimately is whatever management decides it should be. The ratios can be controlled through dividend policy, securities issuances and so forth. Even if the refinancings temporarily alter the capital structure ratios at the time of the refinancing transactions, over time management could restore capital structure ratios to the desired level. There is absolutely no evidence that the projected actual ratios of

9/30/95 differ from management's intention. To assert otherwise suggests that management cannot control the Company's capital structure.

Finally, Mr. Moul's reliance on the NFGD case fails to consider that NFGD's circumstances in that case are not the same as PP&L's circumstances in this case.

Q. MR. MOUL HAS PROVIDED AS AN EXHIBIT A PP&L BOARD RESOLUTION DOCUMENTING THE PLANNED COMMON EQUITY ISSUANCE. DOES THIS ADDRESS THE CONCERN RAISED IN YOUR DIRECT TESTIMONY REGARDING VERIFICATION?

A. The documentation and discussion in Mr. Moul's rebuttal testimony are helpful in verifying PP&L's intention to issue new common stock. However, it is also important to understand that a Board resolution only authorizes issuance of stock; it does not compel such an issuance. As Mr. Hill explained, PP&L's willingness to proceed with securities issuances depends upon conditions in financial markets.

Despite PP&L's current intentions, the amount and timing of an equity issuance remains uncertain. Therefore, PP&L should notify the Commission and the parties of the status of the issuance prior to the final order in this case so that the actual amount of such an issuance can be reflected in the approved capital structure. The projected $100 million of new equity should not be reflected in capital structure unless the issuance actually occurs and this notification is provided.

The Adequacy of an 11.1 Percent ROE

Q. MR. MOUL ARGUES THAT 11.1 PERCENT IS AN INADEQUATE ROE. DO YOU AGREE?

A. No. The ultimate test of what return is adequate is the return which the market requires based on what investors are willing to pay for common stocks. The accepted tool for measuring the return required by investors is the DCF model. Thus, Mr.

Moul's "investor adequacy" argument is nothing more than criticisms of the DCF estimates, and therefore it is on those estimates which we should focus. A review of these estimates reveals that there is no basis for asserting that my 11.1 percent is inadequate or unusual.

As a comparison, however, I would note that a recent Edison Electric Institute (EEI) survey finds that electric utility ROE awards for 1994 averaged about 11.5 percent. (See Electric Utility Week, page 11, March 20, 1995.) While this is slightly higher than my present recommendation, capital costs have declined considerably from 1994, particularly compared to late 1994 levels.

Q. MR. MOUL ARGUES THAT HIS 13 PERCENT ROE MEETS THE OBJECTIVE OF A 4.0X COVERAGE RATIO. IS YOUR RECOMMENDATION INADEQUATE BY THAT MEASURE?

A. No. Following Mr. Moul's pro forma calculation approach, my recommendation provides a pre-tax coverage of 3.5x, which is consistent with a single A bond rating. There is no showing that 3.5x is inadequate for maintaining PP&L's financial integrity.

Q. MR. MOUL ASSERTS THAT YOUR RECOMMENDATION FAILS TO PROVIDE A REASONABLE RETAINED EARNINGS CUSHION. IS THIS A VALID CRITICISM?

A. Not only is this not valid, I am concerned that PP&L would even raise this issue because it implies that the PP&L common dividend is a regulatory variable. In effect PP&L is asking this Commission to approve and validate its dividend payout. The dividend is normally viewed as a matter of management prerogative, and it is not this Commission's job to specifically target earnings levels at some percentage above the dividend. If the Commission were to do so, the incentive would be clear -- utilities would raise the dividend with the understanding that higher authorized ROEs would follow.

Finally, an 11.1 percent ROE does provide a retained earnings cushion above the current dividend, only the cushion is not as large as Mr. Moul and PP&L would like.

Q. MR. MOUL SUGGESTS THAT PP&L WILL NOT EARN ITS AUTHORIZED RETURN DUE TO ATTRITION AND REGULATORY LAG. IS THERE ANY EVIDENCE OF THIS?

A. No. PP&L has presented no analysis suggesting this to be the case. In fact, it is my understanding that PP&L intends to aggressively pursue cost cutting over the next several years. These cost cutting efforts, if successful, will serve to enhance Company earnings.

Q. MR. MOUL ARGUES THAT YOUR RECOMMENDATION WILL NOT PERMIT PP&L TO INCREASE ITS DIVIDEND BY THE 2.5 TO 3.0 PERCENT WHICH YOU ASSUME. IS THIS AN INDICATION THAT YOUR RECOMMENDATION IS INADEQUATE?

A. No. In setting the fair rate of return, it is not the Commission's role or responsibility to ensure that the utility must achieve as an after-the-fact result either a certain return on book equity or rate of dividend growth. For example, consider two utilities equal in risk. Suppose investors expect utility A to be very profitable, i.e., earning 20 percent on book equity and achieving a 10 percent growth rate. Suppose investors are much less optimistic for utility B expecting only a 10 percent ROE and 2 percent growth rate. It does not follow that utility A should be awarded a 20 percent ROE and utility B only a 10 percent ROE. This is the classic confusion of a book return and a market return.

Q. MR. MOUL ARGUES THAT YOUR RETURN PROVIDES ONLY A 0.5 PERCENT GROWTH RATE FOR PP&L. IS THAT ACCURATE?

A. No. The dividend growth rate is under the control of PP&L management, not this Commission, but aside from that conceptual point, I do not agree with Moul's calculations. First, he assumes that total Company PP&L (soon to be PP&L Resources) and Pennsylvania jurisdiction are the same. Second, he employs a 1994 book value, whereas we are using a 1995 future test year in this case for ratemaking. Third, he assumes that internal retained earnings is the only source of growth. My DCF analysis assumes a growth through stock issuance factor of 0.5 percent. Thus, correcting these errors would produce a substantially different result than the 0.51 percent dividend growth rate which Mr. Moul asserts that my 11.1 percent ROE provides.

The conceptual error, however, is much more fundamental than his calculation errors. The <u>market</u> return which the investor expects to earn and the return on book value which the investor expects PP&L to earn are generally not the same. It is the failure to make this distinction which leads to the inconsistency which Mr. Moul asserted on page 6 of his rebuttal testimony.

Q. WOULD MR. MOUL'S OWN DCF STUDY FOR PP&L PASS THIS "CONSISTENCY TEST?"

A. No. If Mr. Moul had subjected his own 12.5 percent DCF result for PP&L to this test, he would have generated the following results:

Moul DCF ROE:	12.5%
PP&L Book Value:	$15.79
Earnings per Share:	$1.97
Dividends per Share:	$1.67

Amount Retained Per Share:	$0.30
Calculated Growth Rate:	1.9%
Recommended Growth Rate:	4.0%

Thus, if Mr. Moul had subjected his own DCF study to this same "consistency test," he would find a growth rate discrepancy comparable to the one he claims for me.

It is the "test" which is flawed, not my DCF analysis.

The DCF Analysis

Q. WHAT ARGUMENTS DOES MR. MOUL ASSERT FOR THE DCF STUDIES?

A. As general comments, he argues that the DCF model is overly restrictive and circular. He also suggests, citing a NARUC survey, that utility commissions rely on a variety of techniques, not just the DCF. These arguments or observations are either overstated or incorrect.

The DCF model is actually a very flexible methodology that can be adapted to analyze a number of growth scenarios. This flexibility, along with theoretical soundness and ease of use, account for its overwhelming popularity. For example, I have used both the two-stage version and constant growth versions of the model, obtaining similar results.

To demonstrate circularity, Mr. Moul offers an example of a slow growth utility, claiming that the DCF model would perpetuate the slow growth. His example is not correct. The DCF model -- if correctly applied -- estimates what return investors require. Mr. Moul's error is in equating slow growth with a low DCF result. The slow growth would likely be accompanied by a high dividend yield and thus a "typical" DCF return, not a depressed return. Moreover, a company's rate of growth is to a large extent determined by management policy. That is, management can select either a high current dividend payout and thus slow growth or a low current payout which results in more rapid growth due to retained earnings reinvestment. Management selects among this spectrum of financial policies. This has nothing to do with the DCF model (unless management's choice affects risk). Moreover, if there is any validity to Mr. Moul's "circularity" theory, this would argue very strongly for the use of a proxy group in place of a PP&L stand-alone study.

Q. DOES THE NARUC SURVEY SUPPORT MR. MOUL'S POSITION?

A. In my opinion, it does not. That survey seems to suggest that the DCF model is the principal method relied upon by utility commissions, with other methods also referenced. A limitation of the survey is that it tells us nothing about relative weights given to different methods. For example, after the DCF, the next most cited method is comparable earnings. However, it has been my experience that almost no weight is given that method in arriving at a final ROE finding for electric utilities.

Q. DOES MR. MOUL DISPUTE YOUR GROWTH RATE ESTIMATES?

A. At page 17, he argues against reliance on earnings retention growth estimates suggesting that in some sense it does not adequately capture total growth. Since he does not explain why he disagrees with this measure, I cannot respond to his disagreement.

As a practical matter, however, this disagreement makes little difference because all other measures of growth which I cite (e.g., Value Line two-stage, IBES projected earnings, etc.) are consistent with my ultimate growth rate findings.

Q. MR. MOUL NOTES THAT THE VALUE LINE ROE FIGURES ARE BASED ON YEAR-END RATHER THAN AVERAGE YEAR EQUITY. DOES THIS AFFECT YOUR ANALYSIS?

A. No. I recalculated the historical Value Line ROEs using average year equity in place of year end. These calculations were supplied to PP&L as part of my workpapers. The Value Line projected ROEs are based on a three-year average, not a single-year.

Even if there is a year-end average year discrepancy in those projections, the effect on the DCF growth rate figures would be negligible.

Q. DOES MR. MOUL PROVIDE ANY SUPPORT FOR HIS 4 PERCENT GROWTH RATE FINDING?

A. No. The 4 percent is not in any way supported by a review of the objective evidence. For example, at page 17, lines 13-19, he seems to argue for reliance on published earnings per share growth rates. But that information supports growth much lower than 4 percent, at least a percentage point lower. At pages 18-19, he attempts to justify his higher number by suggesting investor analysts are omitting factors that are contributing to growth and are being "overly conservative."

Even if these criticisms of investor analysts are accurate (and there is no evidence that Mr. Moul is correct), this is beside the point. In performing a DCF study, it is Mr. Moul's task (and my task) to determine what investors are expecting and what the market requires. It is not our place to determine whether the market is "right."

Q. MR. MOUL PRESENTS INTERNAL RATE OF RETURN CALCULATIONS ON HIS REBUTTAL SCHEDULE 4. ARE THOSE CALCULATIONS CORRECT?

A. No, they contain an error. For example, for his 50-year analysis, he shows a stream of 50 years of per share dividends escalated at 6 percent per year. However, using a 50-year time horizon, Mr. Moul forgot that the investor would receive in year 50 both the dividend ($20.85) <u>and</u> the proceeds from selling the share (another $368.40, i.e., $20 escalated at 6 percent). That is, his schedule omits the sale of the share of stock, originally purchased for $20. This error distorts the results which he shows on Schedule 4.

Other Cost of Equity Methods

Q. MR. MOUL CRITICIZES YOUR SOLE RELIANCE ON THE DCF. IS THIS A FAIR CRITICISM?

A. No. I also performed risk premium and sample CAPM calculations obtaining results similar to but slightly different from my DCF results. While they confirm the general reasonableness of my recommendation, they are not the basis for that recommendation. Since I do not regard either my risk premium or CAPM as being as reliable as my DCF study, it would not be proper to average the three methods together.

Q. WHY DO YOU FIND THE RISK PREMIUM AND CAPM TO BE UNRELIABLE?

A. To some degree, the problems with those methods are highlighted in Mr. Moul's rebuttal testimony. Risk premium studies in almost every case are based upon historic market data sometimes going back many decades. In my case, I used FERC data from 1985-1991, which are far more recent than data used in most risk premium studies. Even so, the use of historic data and market data which may not be specific to the utility in question are serious limitations. For example, my study uses the entire electric utility industry and Mr. Moul uses the S&P 40 utilities, many of which are not even electrics.

A fundamental problem with the CAPM is that it first requires an estimate of the return investors require on the stock market as a whole. Mr. Moul assumes that to be 16 percent, a figure far out of line with both historical experience and published evidence.

Q. WHY DO YOU DISPUTE MR. MOUL'S 16 PERCENT FIGURE?

A. It is clear that investors generally do not expect a long run average return of 16 percent on the stock market. In my direct testimony, I cited the expected return on the

Value Line Industrial Composite, projected to be about 12 to 13 percent. The Industrial Composite broadly reflects corporate America excluding utilities, transportation and financial services. Mr. Moul's complaint is that it includes only 810 companies.

The rate of return projections for the S&P 500, another widely accepted proxy for the overall stock market, are similar. IBES publishes an earnings per share growth rate for the S&P 500 of 9.2 percent. Combining that with the current 2.6 percent dividend yield produces a DCF estimate for the S&P 500 of roughly 12 percent. (Please note that at page 17 of his rebuttal testimony, Mr. Moul advocates focusing on earnings as the proper measure of growth for DCF purposes.) While I am certainly not suggesting relying on the IBES projections of the S&P 500, it clearly shows that Mr. Moul's 16 percent estimate is outlandishly high and contrary to investor requirements.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SCHEDULES ACCOMPANYING

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
FAIR RATE OF RETURN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Overall Rate of Return Recommendation
At September 30, 1995
($000s)

Capital Type	Amount Outstanding (@ 9/30/95)[1]	Percentage of Total Capital	Cost Rate[1]	WACC
Long-Term Debt	$2,873,250	47.56%	7.97%	3.79%
Preferred Stock	449,535	7.44	7.31	0.54
Common Stock	2,718,693	45.00	11.1[2]	5.00
	$6,041,478	100.00%	--	9.33%

[1]Source: Moul, Schedules 4 and 5. The $115.9 million of unamortized balance on reacquisition losses is not removed from debt balance.
[2]Source: Schedule MIK-5, page 1 of 6 and MIK-6, page 1 of 6.

PENNSYLVANIA POWER & LIGHT COMPANY

Recent Trends in Capital Costs

1994	Annualized Inflation Rate[1]	10-Year Treasury Yields	3-Month Treasury Bill	Single A Utility Bond Yields
January	2.5%	5.8%	3.0%	7.3%
February	2.5	6.0	3.2	7.4
March	2.6	6.5	3.6	7.9
April	2.4	7.0	3.8	8.2
May	2.4	7.2	4.3	8.3
June	2.8	7.3	4.4	8.3
July	2.8	7.3	4.4	8.5
August	2.9	7.2	4.5	8.4
September	3.0	7.5	4.8	8.6
October	2.6	7.7	5.0	8.9
November	2.7	7.9	5.4	9.0
December	2.7	7.8	5.8	8.8
1995				
January	2.8	7.8	5.7	8.7
February	2.9	7.5	5.8	8.5
March	2.9	7.2	5.7	8.4
April (preliminary)	--	7.1	5.6	8.3

[1]Inflation rate is the annualized rate of increase in the CPI computed as the CPI level that month compared with 12 months prior value.

Sources: Standard & Poor's Stock Guide, Economic Indicators, Moody's Bond Record, Federal Reserve Statistical Release, Business Week.

PENNSYLVANIA POWER & LIGHT COMPANY

Risk Attributes of the Primary Proxy Companies

	Company	Moody's Bond Rating	Value Line Safety Rating	Beta Statistic	% Nuclear Generation	1994 Common Equity Ratio
(1)	Atlantic Energy	A(3)	2	0.70	24%	45.0%
(2)	Baltimore Gas & Electric	A(1)	2	0.75	40	44.5
(3)	Carolina Power & Light	A(2)	2	0.80	29	47.5
(4)	Delmarva Power & Light	A(2)	2	0.65	14	49.0
(5)	Detroit Edison	A(3)	3	0.70	17	43.0
(6)	Dominion Resources	A(1)	2	0.65	31	44.5
(7)	IES Industries	A(1)	2	0.60	20	51.0
(8)	Kansas City Power & Light	A(2)	2	0.65	25	51.0
(9)	Midwest Resources	A(1)	3	0.50	15	44.0
(10)	New England Electric System	A(3)	2	0.75	18	48.0
(11)	Pacific Gas & Electric	A(2)	3	0.75	17	46.5
(12)	Public Service Enterprise	A(3)	2	0.70	47	46.5
(13)	San Diego Gas & Electric	A(1)	2	0.60	17	50.3
(14)	SCANA	A(1)	2	0.65	22	45.0
(15)	Western Resources	A(3)	2	0.70	17	47.5
	Average	A(2)	2.2	0.68	23.6%	46.8%
	Pennsylvania Power & Light	A(2)	2	0.65	31.0%	43.5%

Source: Moody's Bond Record, February 1995, Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

Monthly Dividend Yields for Mr. Moul's Group (November 1994 - April 1995)

							Averages	
	Nov 1994	Dec 1994	Jan 1995	Feb 1995	Mar 1995	Apr 1995	Feb - Apr 1995	Nov 1994- Apr 1995
Allegheny Power System	7.76%	7.60%	7.21%	6.92%	7.21%	7.02%	7.05%	7.29%
American Electric Power	7.47	7.27	7.07	6.96	7.37	7.43	7.25	7.26
Atlantic Energy	8.96	8.64	8.44	8.21	8.30	8.41	8.33	8.51
Baltimore Gas & Electric	6.87	6.79	6.57	6.24	6.48	6.37	6.36	6.55
Delmarva Power & Light	8.35	8.35	8.24	7.90	7.82	7.77	7.83	8.07
DPL, Inc.	5.81	5.74	5.96	5.82	6.05	5.90	5.92	5.88
PEPCO	8.76	8.82	8.68	8.51	8.76	8.54	8.60	8.68
Public Service Enterprise	8.35	8.25	7.85	7.42	7.82	7.84	7.69	7.92
Average	7.79%	7.68%	7.50%	7.25%	7.49%	7.38%	7.38%	7.52%

Source: Standard & Poor's Stock Guide, December 1994 - May 1995 issues.

PENNSYLVANIA POWER & LIGHT COMPANY

Monthly Dividend Yields for Primary Proxy Group (November 1994 - April 1995)

	Nov 1994	Dec 1994	Jan 1995	Feb 1995	Mar 1995	Apr 1995	Averages Feb - Apr 1995	Averages Nov 1994 - Apr 1995
Atlantic Energy	8.96%	8.64%	8.44%	8.21%	8.38%	8.41%	8.33%	8.51%
Baltimore Gas & Electric	6.87	6.79	6.57	6.24	6.48	6.37	6.36	6.55
Carolina Power & Light	6.57	6.50	6.40	6.29	6.55	6.41	6.42	6.45
Delmarva Power & Light	8.35	8.35	8.24	7.90	7.82	7.77	7.83	8.07
Detroit Edison	7.85	7.70	7.63	7.18	7.47	7.36	7.34	7.53
Dominion Resources	7.13	7.03	7.00	6.72	7.02	7.06	6.93	6.99
IES Industries	8.24	8.17	7.96	7.81	8.08	8.93	8.27	8.20
Kansas City Power & Light	6.89	6.63	6.52	6.38	6.63	6.66	6.56	6.62
Midwest Resources	8.47	8.67	8.40	8.21	8.29	8.14	8.21	8.36
New England Electric System	7.51	7.37	7.08	6.87	7.21	7.46	7.18	7.25
Pacific Gas & Electric	8.50	8.04	7.86	7.74	7.80	7.54	7.69	7.91
Public Service Enterprise	8.35	8.25	7.85	7.42	7.82	7.84	7.69	7.92
San Diego Gas & Electric	7.77	7.74	7.53	7.41	7.49	7.47	7.46	7.56
SCANA	6.67	6.63	6.53	6.47	6.75	6.80	6.67	6.64
Western Resources	6.99	6.95	6.50	6.09	6.35	6.30	6.25	6.53
Average	7.67%	7.57%	7.36%	7.13%	7.34%	7.37%	7.28%	7.41%
Pennsylvania Power & Light	8.48%	8.54%	8.43%	8.14%	8.38%	8.76%	8.43%	8.46%

Source: Standard & Poor's Stock Guide, December 1994 - May 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

DCF Analysis Summary for Mr. Moul's
Proxy Group of Electric Utility Companies

(1)	Dividend Yield (November 1994 - April 1995)	7.52%[1]
(2)	Adjusted Yield (7.52 x 1.02)	7.7
(3)	Growth Range	3.0 - 3.5
(4)	Cost of Equity	10.7 - 11.2
	Midpoint	11.0%
	RECOMMENDATION	11.1%

[1]Schedule MIK-4, page 1 of 2.
[2]DCF formula is as follows:

K_e = Do/Po (1 + 0.5g) + g, where

K_e = cost of equity

Do = indicated quarterly dividend x 4

Po = stock price

g = annualized dividend growth rate

PENNSYLVANIA POWER & LIGHT COMPANY

DCF Analysis Summary for the Primary Group of Proxy Companies

(1)	Dividend Yield (November 1994 - April 1995)	7.41%[1]
(2)	Adjusted Yield (7.41 x 1.02)	7.6
(3)	Growth Range	3.0 - 4.0
(4)	Cost of Equity	10.6 - 11.6
	Midpoint	11.1%
	RECOMMENDATION	11.1%

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[1]Schedule MIK-4, page 2 of 2.
[2]DCF formula is as follows:

K_e = Do/Po (1 + 0.5g) + g, where

K_e = cost of equity

Do = indicated quarterly dividend x 4

Po = stock price

g = annualized dividend growth rate

PENNSYLVANIA POWER & LIGHT COMPANY

Earnings Retention Analysis for Primary Proxy Group

Year	(1) ROE	(2) Retention Rate	(3) Implied Growth (1)x(2)
1985	14.21%	27.79%	3.95%
1986	14.07	28.09	3.95
1987	14.00	26.91	3.77
1988	13.00	21.55	2.80
1989	13.31	20.84	2.77
1990	12.72	16.63	2.12
1991	12.91	17.36	2.24
1992	11.58	14.00	1.62
1993	12.60	20.63	2.61
1994	11.89	17.38	2.07
Last 5 Years	12.34%	17.20%	2.12%
Last 10 Years	13.03%	21.12%	2.75%
Average of Last 5 & 10 Yrs	12.69%	19.16%	2.43%
Best 3 Years ROE	14.09%	27.60%	3.89%

Source: Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

Historical Growth Rates For Earnings, Dividends and Book Value per Share for Primary Proxy Group (annualized compound growth rates)

	Dividends Per Share	Earnings Per Share	Book Value Per Share	Average
Last 5 Years (1)	2.05%	1.13%	3.07%	2.08%
Last 10 Years (2)	2.46	0.55	2.68	1.90
Average	2.26%	0.84%	2.88%	1.99%

(1) Based on 1989 to 1994.
(2) Based on 1984 to 1994.

Source: Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

Value Line Projections for
Primary Proxy Group

Company	Near Term Dividend Growth Rate[1]	Long-Term Growth Rate[2]	Weighted Average[3]	Future ROE (1997-1999)
Atlantic Energy	0.00%	3.5%	2.33%	11.5%
Baltimore Gas & Electric	2.87	3.0	2.96	11.0
Carolina Power & Light	2.38	4.0	3.46	13.5
Delmarva Power & Light	0.96	2.0	1.65	11.5
Detroit Edison	1.43	4.5	3.48	13.0
Dominion Resources	1.53	2.5	2.18	11.0
IES Industries	0.71	3.5	2.57	12.0
Kansas City Power & Light	2.57	4.5	3.86	14.0
Midwest Resources	2.49	3.5	3.16	12.0
New England Electric System	1.91	3.5	2.97	11.5
Pacific Gas & Electric	0.76	4.0	2.92	12.0
Public Service Enterprise	0.69	3.5	2.56	12.0
San Diego Gas & Electric	2.53	4.0	3.51	14.5
SCANA	2.39	3.0	2.80	12.0
Western Resources	1.96	3.0	2.65	10.5
Average	1.69%	3.47%	2.88%	12.14%

(1) Annualized growth rate in dividends per share, 1994-1998.

(2) Earnings retention growth rate (1997-1999) published by Value Line plus an assumed 0.5 percent for possible "external" growth.

(3) Weighted average growth rate places one-third weight on near-term growth and two-thirds weight on long-term.

Source: Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY
Five Year Earnings Projection For
Primary Proxy Group
Value Line vs. IBES

	Value Line		"IBES"	
Company	1994-1998	"Normalized"	Growth Rate	No. of Estimates
Atlantic Energy	4.66%	3.0%	1.8%	5.0
Baltimore Gas & Electric	2.99	5.0	3.5	11.0
Carolina Power & Light	3.25	1.5	3.1	13.0
Delmarva Power & Light	3.70	3.0	3.0	7.0
Detroit Edison	3.15	-3.0	1.8	8.0
Dominion Resources	3.23	2.5	2.5	12.0
IES Industries	3.85	2.5	2.7	5.0
Kansas City Power & Light	8.06	6.5	3.3	6.0
Midwest Resources	7.71	7.5	2.6	3.0
New England Electric System	1.17	2.0	2.5	12.0
Pacific Gas & Electric	1.24	3.5	1.8	8.0
Public Service Enterprise	1.77	3.5	2.7	11.0
San Diego Gas & Electric	5.28	3.0	2.3	8.0
SCANA	4.53	3.0	3.1	6.0
Western Resources	2.87	2.0	2.5	9.0
Average	3.82%	3.03%	2.62%	8.3

Source: Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

Illustrative Analysis of
the External Growth Component for
Primary Proxy Group

Company	(1) Growth Rate in Common Shares (1994-1998)	(2) Mkt/Book Premium	(3) External Growth Rate Component (1)x(2)
Atlantic Energy	0.37%	4.97%	0.02%
Baltimore Gas & Electric	1.08	11.72	0.13
Carolina Power & Light	-0.41	37.43	-0.15
Delmarva Power & Light	0.21	11.99	0.03
Detroit Edison	-2.48	7.09	-0.18
Dominion Resources	1.63	23.33	0.38
IES Industries	1.69	16.80	0.28
Kansas City Power & Light	0.00	35.24	0.00
Midwest Resources	1.10	5.64	0.06
New England Elec. System	0.00	14.26	0.00
Pacific Gas & Electric	0.93	13.47	0.13
Public Service Enterprise	0.07	12.15	0.01
San Diego Gas & Electric	0.58	36.59	0.21
SCANA	4.16	25.44	1.06
Western Resources	0.00	14.52	0.00
Group Average	0.60%	18.05%	0.14%

(1) Value Line projections in common shares outstanding, 1994-1998.
(2) Premium calculated as (1 - BVPS/0.95P) where BVPS is 1994 book value per share, P is Value Line's "Recent Price" and 0.95 is a net proceeds adjustment factor.

Source: Value Line Investment Survey, December 16, 1994, January 13 and February 24, 1995.

PENNSYLVANIA POWER & LIGHT COMPANY

DCF Analysis Summary of
PP&L Stand-Alone

(1)	Dividend Yield (Nov. - April 1995)	8.46%[1]
(2)	Adjusted Yield (8.46 x 1.02)	8.6
(3)	Growth Range	2.5 - 3.0
(4)	Cost of Equity	11.1 - 11.6
	Midpoint	11.3%
	RECOMMENDATION	11.1%

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[1]Schedule MIK-4, page 1 of 2.
[2]DCF formula is as follows:

K_e	=	Do/Po (1 + 0.5g) + g, where
K_e	=	cost of equity
Do	=	indicated quarterly dividend x 4
Po	=	stock price
g	=	annualized dividend growth rate

OCA STATEMENT NO. 1B
R-943271 5/23/95
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
OTHER FINANCIAL ISSUES

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

THE SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
OTHER FINANCIAL ISSUES

I. OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. My business address is 12510 Prosperity Drive, Silver Spring, Maryland 20904. I am a Senior Economist and Principal at Exeter Associates, Inc., a consulting firm specializing in public utility regulation and energy studies. I have held that position since January 1981.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I have. In early April 1995, I submitted direct testimony on behalf of the Office of Consumer Advocate (OCA) on the subject of fair rate of return to be applied to the Pennsylvania jurisdictional rate base of Pennsylvania Power & Light Company (PP&L). That testimony also addressed the expected earnings on nuclear decommissioning trust funds. At the same time I submitted separate testimony concerning the generation capacity issues in this case. (OCA Statement No. 2) A statement of my qualifications and listing of past testimony accompanied my direct testimony (OCA Statement No. 1) filed in April.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY ON OTHER FINANCIAL ISSUES.?

A. My surrebuttal testimony at this time responds to several financial issues discussed in PP&L rebuttal testimony. I respond to Mr. Moul's discussion of deferred taxes resulting from debt call premiums (i.e., losses on reacquisition); to Mr. Berish concerning projected financial impacts of the OCA recommendations; and to Mr. Chappelear concerning nuclear decommissioning trust fund earnings.

Q. CAN YOU SUMMARIZE YOUR RESPONSES TO THESE WITNESSES?

A. Yes. Mr. Chappelear takes issue with my 7.2 percent net of tax and transaction cost earnings estimate on the nuclear decommissioning trust fund. He does not in anyway demonstrate that my 7.2 percent is unrealistic. Rather, his principal point is that PP&L has employed an escalation rate for decommissioning costs which may be understated. In my opinion, the projected cost of decommissioning and the realistic earnings rate on trust fund assets are determined separately. It is incumbent on PP&L to select realistic parameters for both costs and trust fund earnings.

Mr. Moul disputes Mr. Catlin's recommendation that deferred taxes arising from call premiums should be subtracted from rate base. I believe Mr. Moul has mischaracterized the issue. Later in his rebuttal testimony, he suggests that an alternative way of recognizing the deferred taxes is through rate of return rather than rate base. I find Mr. Moul's alternative to be acceptable, provided that PP&L's actual capital structure, not adjusted capital structure, be used in this case. Including deferred taxes in rate of return lowers my overall return by six basis points from 9.33 to 9.27

percent. However, if the Commission accepts Mr. Moul's capital structure approach (which increases the equity ratio above the actual level), then Mr. Catlin's original position should be followed and deferred taxes netted from rate base.

Finally, Mr. Berish discusses the projected impact of the OCA's rate reduction recommendation on PP&L's 1996 earnings. I cannot agree with either his analysis or the implications of that analysis. To some extent, his projected results may be the result of Mr. Berish assuming different costs and accounting treatments than assumed by Mr. Catlin. Moreover, his projected earnings decline may be due in part to pessimism regarding PP&L revenues in the wholesale market. This should not be the basis for rejecting the OCA's set of recommendations in this case.

II. NUCLEAR DECOMMISSIONING TRUST FUND EARNINGS

Q. HOW DID PP&L ADDRESS THE ISSUE OF EARNINGS ON THE SUSQUEHANNA NUCLEAR DECOMMISSIONING TRUST FUND (NDT)?

A. PP&L sponsors the rebuttal testimony of Mr. John M. Chappelear, the Company's officer in charge of investing the NDT. The issue which his testimony is intended to address is the appropriate projected or expected long-run average rate of return on NDT assets. As originally sponsored by Mr. Hill, PP&L projects a net of tax and transaction cost rate of return of 5.5 percent, or 1.5 percent over inflation. My position is that a 5.5 percent expected return is an unreasonably low and pessimistic projection. More to the point, such a return is totally inconsistent with the findings of all four rate of return witnesses in this case. After examining the authoritative, available long run projections of capital costs, I concluded that a reasonable projection would be 7.5 percent, post-tax. After deducting transaction costs, my return estimate becomes 7.2 percent, which is the earnings figure employed by OCA witness Catlin.

Q. IN WHAT WAY DOES MR. CHAPPELEAR DISAGREE WITH YOUR NDT EARNINGS ANALYSIS?

A. He makes several points concerning my 7.2 percent earnings figure (which he refers to as 7.5 percent). First, he acknowledges that Mr. Hill's 5.5 percent assumption is conservative and concedes that the "Company might earn more than 5.5%," but he argues that the assumed 4 percent escalation rate for decommissioning costs is also conservative and possibly understated. Second, he defends the Company's planned asset allocation target of 30 percent for common equities. Third, he questions my projection of a return on trust fund equity assets of 12 percent.

Q. DOES PP&L'S USE OF A "CONSERVATIVE" 4 PERCENT COST ESCALATION RATE INVALIDATE YOUR 7.2 PERCENT TRUST FUND EARNINGS RATE?

A. No, this is an unreasonable argument. At page 4 he states:

> If the opposing parties wish to employ more aggressive earnings assumptions, then they also should employ more realistic assessments of future cost of decommissioning the plant.

In the first place, my earnings assumption of 7.2 percent is hardly "aggressive." It is an estimate completely supported by market data and authoritative projections. Mr. Chappelear's position is that the OCA is obligated to employ an obviously unrealistically low earnings estimate simply because PP&L now has misgivings over its own cost escalation rate projection developed by its own expert. PP&L must take responsibility for the realism of its own projections of cost, and not use its misgivings over those projections as the basis for biasing a completely separate aspect of decommissioning, i.e., trust fund earnings. This "two wrongs make a right" logic must be rejected.

Q. MR. CHAPPELEAR DEFENDS THE 30 PERCENT EQUITY ALLOCATION. HOW DOES THIS AFFECT YOUR 7.2 PERCENT EARNINGS ESTIMATE?

A. It has no effect. Although I would question an equity allocation of only 30 percent, I accepted that figure in developing my 7.2 percent earnings estimate. This is one reason why my recommendation should be viewed as conservative.

Q. MR. CHAPPELEAR APPEARS TO TAKE ISSUE WITH THE USE OF AN EQUITY RETURN EQUAL TO PP&L'S CLAIMED EQUITY RETURN. DOES HIS POSITION HAVE MERIT?

A. No. It is my position that the return expected by investors on the overall stock market should exceed PP&L's cost of equity by at least a small amount. I used a 12 percent stock market return, which compares to PP&L's ROE request of 13 percent and Mr. Moul's projection of (investor expected) stock market returns of 16 percent. Thus, my 12 percent is far more conservative than the return PP&L's own witness claims the market as a whole is expecting. I have shown in my direct and surrebuttal testimony that a reasonable expectation for the stock market as a whole is approximately 12 percent, which is approximately 3.5 to 4.0 percent greater than the long run return on corporate bonds projected by Blue Chip Economic Indicators.

Mr. Chappelear's objection is that the rate case ROE is a short run (e.g., test year) measure of market returns. This view is simply wrong. Since corporate common stock is a perpetuity, the costs of equity estimated by all four witnesses in this case are of necessity the long-run average returns projected by investors. The DCF model used by all witnesses is a long run model.

Q. DOES MR. CHAPPELEAR DEMONSTRATE THAT YOUR EARNINGS PROJECTIONS ARE EITHER INCONSISTENT WITH AVAILABLE EVIDENCE OR UNREALISTIC?

A. No. I assume an 8 percent return on bonds and 12 percent on equity investments, pre-tax. Mr. Chappelear provides no evidence that these are unrealistic estimates of investment returns. Indeed, his complaint seems to be that they <u>are</u> realistic, and that I should have deliberately used unrealistically low estimates to compensate for PP&L's selection of a 4 percent cost escalation rate.

III. <u>DEFERRED TAXES AND LOSSES ON REACQUIRED DEBT</u>

Q. WHY ARE THE DEFERRED TAXES ASSOCIATED WITH LOSSES ON REACQUIRED DEBT AT ISSUE IN THIS CASE?

A. As previously explained, PP&L incurred call premiums (losses on debt reacquisition) over a period of years, principally between 1986 and 1993, when refinancing its high cost debt. In addition to receiving large net interest expense savings in those years (which went to shareholders), PP&L also received immediate tax write-offs. Those losses could be expensed for tax purposes in the year incurred. For accounting purposes, those losses are treated as a regulatory asset on a pre-tax basis and amortized over a very long period of time. Per Mr. Moul's proposal, PP&L recovers the amortizations and a return on the unamortized balance in rates through higher interest expense, i.e., a higher embedded cost of debt. With interest synchronization, the dollar amount of PP&L's original tax savings is returned to ratepayers very gradually over time.

This practice gives rise to a tax timing difference, and hence, deferred taxes. In other words, shareholders have already received the tax savings but ratepayers will only see the tax savings gradually over the next 10 to 15 years. Neither the existence nor the magnitude of this deferred tax balance related to call premiums (about $48 million) is in dispute.

PP&L chose to ignore these deferred taxes entirely for purposes of this rate case. Mr. Catlin, on behalf of the OCA, deducted them from rate bases, which I believe is a standard treatment.

Q. WHAT POSITION DOES MR. MOUL TAKE ON REBUTTAL?

A. He makes two arguments. First, he claims that Mr. Catlin's rate base recognition of the deferred taxes is improper because the loss on reacquisition balance is not being given rate base recognition. Second, he notes that the losses were financed with investor, not ratepayer funds. Third, ratepayers will receive their share of the tax benefits through interest synchronization. Fourth, he asserts that Mr. Catlin's proposal gives ratepayers the tax benefit "up front." Finally, he argues that subtracting deferred taxes from rate base provides ratepayers the savings at the overall rate of return, whereas PP&L requests only a debt return on the unamortized balance.

Mr. Moul acknowledges that if deferred taxes are to be recognized, this recognition should take place through rate of return, not rate base. In doing so, he lowers the cost of debt from 7.97 to 7.84 percent and the overall return from 10.22 to 10.15 percent.

Q. ARE MR. MOUL'S ARGUMENTS CONCERNING DEFERRED TAXES CORRECT?

A. No, several of his arguments are in error and require clarification. Consider his argument that call premiums were financed by investors and not ratepayers. This assertion is only partly true. The call premiums were financed partly by investors (i.e., about 60 to 65 percent) and partly by the U.S. Treasury due to the tax write-off. PP&L should only receive a return on the portion of the unamortized balance financed by investors. That is why deferred taxes must be recognized. Mr. Moul's other argument that ratepayers receive their appropriate share of the tax savings through interest synchronization misses the essential point. The issue with the deferred taxes is not whether the tax benefit dollars will be passed on to ratepayers but when. Deferred taxes is a timing issue.

Mr. Catlin's recognition of deferred taxes does not front load the tax benefit for ratepayers, as Mr. Moul asserts. Rather, its purpose -- as is always the case with deferred tax recognition -- is to ensure that the Company only receives a return on the investor-financed portion of the asset, not on the portion financed by the taxing authority or ratepayers.

Q. MR. MOUL'S CENTRAL POINT IS THAT THE UNAMORTIZED CALL PREMIUMS ARE NOT GIVEN RATE BASE RECOGNITION. IS HE CORRECT?

A. Mr. Moul is essentially correct in describing the OCA's position. In accordance with Pennsylvania practice, expenses such as call premiums are not given rate base treatment. I have, however, imputed a debt return on the unamortized balance, which Mr. Moul accepts as a "full return."

Mr. Moul is incorrect in describing his own rate treatment of the call premiums. Because he subtracts the unamortized balance from debt balance for capital structure purposes he is in effect giving that balance a combined debt plus equity return, i.e., the dollar equivalent of putting it in rate base.

.Q CAN YOU DEMONSTRATE THIS?

A. As I explained in my direct testimony, Mr. Moul's treatment gives PP&L approximately $24 million in rate recovery. This breaks down as $7.2 million in annual amortization and about $16.8 million in debt and equity return dollars, total Company. PP&L has not disputed these figures. Let's suppose instead that PP&L had included the amortization as a conventional expense item and placed the $115.9

million unamortized balance of call premiums in rate base. PP&L then would collect the $7.2 million expense plus a pre-tax return of 14.96% x $115.9 million = $17.3 million or a total of $24.5 million. (The 14.96 percent is Mr. Moul's pre-tax rate of return.) Thus, Mr. Moul's proposed rate of return treatment gives PP&L the same dollar amount as if it received rate base treatment on the unamortized balance. By including the call premium adjustment in rate of return, PP&L hides the fact that it is seeking a rate base equivalent rate of return (including income tax gross up) for an expense item.

Q. WHAT DOES THIS IMPLY?

A. Mr. Moul's theory on rebuttal is that no rate base recognition should be given deferred taxes because the unamortized balance of call premiums is not in rate base. As I have just shown, it is equivalent to rate base treatment. Thus, if the Commission decides to accept Mr. Moul's position and deduct the unamortized balance of call premiums from debt balance <u>for capital structure purposes</u>, then it is imperative that deferred taxes be given rate base offset treatment, as Mr. Catlin recommends.

Q. SUPPOSE THE COMMISSION ACCEPTS YOUR POSITION ON CAPITAL STRUCTURE, I.E., USING PP&L'S ACTUAL CAPITAL STRUCTURE?

A. In that case, I find acceptable Mr. Moul's recognition of deferred taxes in the cost of debt in lieu of rate base. The deferred tax recognition lowers the embedded cost of debt from 7.97 to 7.84 percent, and lowers my overall rate of return from 9.33 to 9.27 percent. My capital structure ratios are not altered by this adjustment.

IV. FINANCIAL CONDITION

Q. PP&L WITNESS BERISH ASSERTS THAT THE OCA'S RECOMMENDATION IN THIS CASE WOULD UNREASONABLY IMPAIR

PP&L'S FINANCIAL CONDITION. PLEASE COMMENT.

A. Mr. Berish predicts that under the OCA recommendation, PP&L's 1996 return on equity would decline to 7.5 percent and its coverage ratio to 2.7x. His implication is that the OCA's overall position is unreasonable on financial grounds and therefore must be rejected for that reason.

I have several concerns regarding his position. First, to some degree Mr. Berish's projections simply reflect the rate case disagreements over the cost data and accounting treatments. For example, Mr. Catlin arrives at a jurisdictional cost of service estimate much different than that claimed by PP&L. I assume that Mr. Berish's earnings projections are based upon his cost of service estimate, not Mr. Catlin's. With two exceptions, the OCA's revenue recommendation is targeted to a return on equity of 11.1 percent. I have already demonstrated (using Mr. Moul's pro forma technique), that this translates into a pre-tax coverage ratio of 3.5x, an entirely adequate coverage for sustaining a single A bond rating.

My second concern is that the weak earnings predicted for 1996 may be due to expected poor performance in the wholesale (i.e., FERC) jurisdiction. This may be due to a combination of market-based pricing and the JCP&L capacity phase-out. PP&L's predictions of weak performance in 1996 in the wholesale market should not serve as a reason to increase the Pennsylvania jurisdictional rates in this case.

Q. YOU STATE THE OCA'S RATE RECOMMENDATION TARGETS AN ROE OF 11.1 PERCENT, WITH TWO EXCEPTIONS. WHAT ARE THOSE EXCEPTIONS?

A. The OCA's rate reduction includes two cost disallowances. One is the Susquehanna Unit 2 common equity return disallowance and the other is the sharing of the economic development rate discounts, as recommended by Dr. Johnson. These two adjustments must be evaluated on their own merits based on PaPUC policy and the record in this case. They should not be simply dismissed out of hand because of PP&L projections of its 1996 earnings.

In summary, the OCA does not agree with Mr. Berish's projections, and it certainly does not agree that those projections form the basis for dismissing the OCA's set of recommendations in this case.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

PA PUBLIC UTILITY COMMISSION
V. PENNSYLVANIA POWER & LIGHT
COMPANY
DOCKET NO. R-00943271

OCA CROSS EXAMINATION EXH.NO. 19

DATE ENTERED: 5/23/95

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SUMMARY OF SCREENING RESULTS FOR THE ARPR

SCREEN SCORE	OPTION	SEASON	LEAD TIME TO FULL IMPL. (YEARS)	PARTIC. BENEFIT YES/NO	PARTIC. B/C RATIO	NON-PART B/C RATIO	UTILITY B/C RATIO	UTILITY NET PRESENT VALUE BENEFITS-COSTS ($)
9.65	MARTINS CREEK GAS CONVERSION	annual	2	YES	6.3	6.3	6.3	182,408,016
9.35	CONTINUE LEASED CT OPERATION	annual	0	YES	7.0	7.0	7.0	67,880,291
8.45	SSES EXTENDED UPRATES	annual	6	YES	3.2	3.2	3.2	130,461,290
7.23	RESIDENTIAL DIRECT LOAD CONTROL	annual	4	YES	10.0	1.0	1.0	1,842,421
6.80	CT ADVANCED (GAS)	annual	3	NO	1.1	1.1	1.1	8,007,900
6.40	I&C-ENERGY CONSCIOUS CONSTRUCTION-GSHP	annual	2	YES	5.7	0.7	2.6	2,220,000
6.40	I&C-EFFICIENT ENERGY MANAGEMENT-AUDITS	annual	2	YES	55.8	0.6	1.4	438,000
5.95	RES.-HOME ENERGY ANALYSIS	annual	2	YES	5.9	0.4	1.8	3,496,000
5.95	RES.-ENERGY EFFICIENT EQUIPMENT-HEHP	annual	2	YES	7.3	0.3	1.1	1,135,000
5.95	I&C-EFFICIENT ENERGY MANAGEMENT-GSHP	annual	2	YES	5.3	0.5	1.2	427,000
5.20	RES.-THERMAL INTEGRITY	annual	2	YES	3.5	0.4	1.8	6,781,000
5.20	RES.-ENERGY EFFICIENT EQUIPMENT-GSHP	annual	2	YES	2.9	0.3	1.4	3,542,000
5.08	RES.-LEASED WATER HEATER (PILOT)	annual	2	YES	0.8	0.8	1.0	(102,000)
4.65	RES.-ELECTRIC THERMAL STORAGE	annual	2	YES	2.6	0.1	0.7	(199,000)
4.55	COMBINED CYCLE, ADVANCED (GAS)	annual	4	NO	0.9	0.9	0.9	(59,450,522)
4.53	AREA LIGHTING	annual	2	YES	n/a	0.9	0.9	(417,000)
4.20	HYDRO – PUMPED STORAGE	annual	9	NO	0.5	0.5	0.5	(1,060,734,071)
3.98	FUEL CELL–PHOSPHORIC ACID	annual	3	NO	0.3	0.3	0.3	(47,015,763)
3.80	COMBINED CYCLE, ADVANCED (OIL)	annual	4	NO	0.3	0.3	0.3	(285,023,913)
3.30	AFB CIRCULATING BED–200MW	annual	8	NO	0.3	0.3	0.3	(481,887,902)
3.08	PULVERIZED COAL UNIT–300MW	annual	8	NO	0.3	0.3	0.3	(603,541,148)
2.78	IGCC–500MW	annual	9	NO	0.5	0.5	0.5	(827,188,944)