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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

w/exhibits
RLC-1 to
RLC-6

APPLICATION OF PENNSYLVANIA POWER & LIGHT COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	DOCKET NO. R-00973954

DOCUMENT
FOLDER

DIRECT TESTIMONY

OF

RICHARD LA CAPRA

On Behalf of:
OFFICE OF CONSUMER ADVOCATE

JULY 1997

Direct Testimony of Richard La Capra

I. Qualifications and Purpose

Q. Mr. La Capra, please identify yourself for the record and summarize your experience and qualifications.

A. My name is Richard La Capra and my business address is 333 Washington Street, Boston, MA 02108. I am a principal of La Capra Associates, a Boston-based consulting firm specializing in energy planning and regulatory economics. I hold degrees in electrical and mechanical engineering from Stevens Institute of Technology. In addition, I also hold a Master of Business Administration degree from Fairleigh Dickenson University, and have done advanced studies in Finance at New York University. I founded La Capra Associates in 1980 with a goal of providing state-of-the-art, innovative technical analysis to the utility industry. I had previously been in charge of the utility business division of Charles T. Main, Inc.

My experience has encompassed financial, ratemaking, load research, and generation supply planning issues. Over the last 26 years, I have worked on behalf of more than 50 clients in 26 states, and in several different countries, on issues involving utility and energy markets. Although my primary interest has been in the area of electric and gas utility regulation, I have also testified on telecommunications, water resources, and the regulated taxicab industry. I have contributed to seminal research in ratemaking and load research, and my clients have relied upon me for technical analysis, strategic guidance, and difficult negotiation assistance.

Of particular relevance to this proceeding is my knowledge of electric industry restructuring concepts and proposals, competitive market pricing in a restructured generation market, and utility finance and ratemaking. I have assisted several New England utilities negotiate short- and long-term power purchase contracts with large wholesale electric companies such as New England Power Company and Northeast Utilities. I have testified as an expert witness on numerous occasions before public utility commissions including the New Hampshire Public Utilities Commission and the

Rhode Island Public Utilities Commission on electric industry restructuring and market price issues. Exhibit RLC-1 is my resume which summarizes my experience and qualifications.

Q. What is the purpose of your testimony?

A. My testimony reviews the Company's derivation of its stranded costs and Competitive Transition Charge (CTC) and presents my recommendations for changes to the Company's request.

Q. Please describe the contents of your testimony.

A. The first subject which I will address will be general criteria for recovery of stranded costs. Second, I discuss the appropriate stranded cost methodology and present my analysis of PP&L's stranded costs. The third topic I address is the mitigation of stranded costs. The next section contains my recommendations for the sharing of stranded costs. Finally, I propose the specific stranded cost amounts that should be allowed into the CTC.

II. Criteria for Recovery of Stranded Cost

Q. What general criteria should be satisfied in determining stranded cost to be responsive to the act and to be in the public interest?

A. I believe that the Act and the public interest requires that the amount of stranded cost allowed should satisfy several general criteria:

- The assets would be stranded in the most reasonable future market scenario in which competition replaces regulation in the generation service function;
- The assessment of stranded costs must be made on a 'net' basis (in which assets with positive value are netted against those which are negative);
- The costs must be non-mitigable, meaning that they are net of reasonable opportunities to be reduced;

- The amounts would have been recovered under traditional regulation and are known and measurable;
- With respect to utility-owned generation related assets, even if costs are found to be stranded under the above criteria, the Commission must determine what level of recovery of such costs is just and reasonable.

These principles have guided my analysis of the appropriate recovery of stranded cost.

Q. Would you please discuss how these criteria relate to the various types of stranded costs?

A. It is essential that the assets to be recovered would have been reasonably recoverable under traditional regulation. In addition, these costs, under the statute, must be known and measurable, presented on a net present value basis, and fit within the definition of stranded cost provided by the statue.

The statutory definition sets forth three general categories of stranded cost recovery.

The first category consists of regulatory assets, deferred charges, unfunded portions of projected nuclear decommissioning costs, and cost obligations with non-utility generating projects that have received a Commission order. For this category of costs, recovery is pursuant to Section 2808(c)(l) which provides that the Commission shall allow recovery of such costs once it is determined that they have met the requirements of the definition.

The second category of costs are associated with prudently incurred costs related to the buyout, buydown, cancellation, or renegotiation of non-utility generation contracts. The recovery of costs in this category is governed by Section 2808(c)(2) which provides that the Commission shall allow recovery of such costs once it is determined that they have met the requirements of the statute.

The third category of costs are those associated with a utility's own generating assets, recovery of which is under Section 2808(c)(3). For a utility's own generating assets, the statute requires that any recovery from ratepayers be just and reasonable under the terms of the new statute. Even if a utility's own prudently incurred generating asset costs are found to be stranded, it still must be demonstrated that recovery from ratepayers of any or all of these costs is just and reasonable.

The generation-related assets being sought for recovery should be truly stranded (on a net non-mitigable basis) after the introduction of retail competition, and under the most reasonable future scenario. If, under the most reasonable future assumptions, the assets in question are able to earn sufficient returns in a competitive environment, there would be no reason for special stranded cost recovery. In fact, allowing stranded cost recovery over a seven year time frame could result in ratepayers subsidizing shareholder profits, and could eliminate an important incentive for electric companies to efficiently reduce going-forward costs in order to mitigate stranded asset values.

Q. Please explain why it is important to use the most reasonable future scenario.

A. The most reasonable future scenario is important in this case to equitably allocate the potential opportunities and risks between the stockholders and ratepayers.

This restructuring will have the same effect as an outright sale of the generating assets on the PP&L franchise ratepayers. Under the restructuring plan, certain rights and obligations will undergo fundamental change. The effective ownership of generation assets, risks of operation, and potential gains from the competitive market will shift to unregulated operations of the Company.

Under traditional regulation, a gain on an asset was generally considered as a cost item in ratemaking. If a utility sold a depreciable asset at a price above its net book value, the gain after taxes was recognized as a reduction to its electric revenue requirements. After restructuring is complete, the utility is the owner of each generation-related asset and is the beneficiary of any subsequent gain or loss.

In this context, the most reasonable future scenario is one that is reasonably centered within the range of possible future outcomes.

III. Stranded Cost Methodology and Analysis

Q. Have you reviewed the Company's estimates of stranded costs?

A. Yes, I have. The Company estimated its stranded cost for all four categories to be $4.61 billion net present value ("NPV") as of 1/1/99. Exhibit RLC-2 presents a summary of the Company's stranded cost estimate for each of the categories, along with a summary of my estimates. Generation-related stranded costs are 75% of the Company's total estimated stranded cost. Above market NUG contract costs account for nearly 15% of the total. Regulatory assets and nuclear decommissioning together make up the remaining 10%.

Q. Are the Company's proposed stranded costs a reasonable estimate of those costs?

A. No, they are not. As my testimony will show, the Company's estimate is very substantially overstated. I have estimated the Company's stranded cost to be $383 million, less than 10% of the Company's estimate.

Q. Please describe the components of stranded costs that are relevant to PP&L.

A. The Company has included stranded costs in each of the three categories identified in the Act:

1) Regulatory assets and other deferred charges, and the unfunded portion of nuclear generating plant decommissioning costs;

2) Cost obligations under contracts with non-utility generators and associated costs of buyout, buydown, termination, or restructuring of these contracts; and

3) Generation-related costs.

In its filing, the Company has grouped its costs into somewhat different categories. My testimony reviews the Company's stranded costs in each of the categories listed above.

Regulatory Assets

Q. What do you believe should be included in stranded costs of the Company's claimed regulatory assets?

A. Mr. Thomas Catlin of Exeter Associates has testified on behalf of the OCA as to the correct values for regulatory assets. His testimony reviews PP&L's claims for stranded costs associated with unrecovered energy costs, the DOE assessment, Susquehanna deferred refueling costs, employee transition costs, 1994 rate case expenses, and the regulatory liability associated with Investment Tax Credits. He recommends that the Company's requested $383.9 million NPV of regulatory assets be reduced by $124.6 million to $259.3 million.

I have incorporated Mr. Catlin's recommendations into my assessment of PP&L's stranded costs.

Q. Did you assist or advise Mr. Catlin in his review of these regulatory asset values?

A. Yes, in three areas. I reviewed the Company's request associated with unrecovered energy cost and recommend that the requested values for 1997 and 1998 be excluded from the Company's request. Second, I reviewed recent Commission decisions on the allowed return on common equity and, as a result, recommend a lower discount rate be used in computing net present value. Third, I provided PUC jurisdictional allocation factors to Mr. Catlin.

Q. What are the unrecovered energy costs that are in dispute?

A. The Company has requested stranded cost collection for a regulatory asset that includes an actual undercollection of fuel costs of $17.2 million that would have been recovered under the ECR and future uncollected energy costs of $31.5 million per year for 1997 and 1998. The projected uncollected energy costs issue was created when the ECR was discontinued as of 1/1/97 and the Company rolled-in an energy cost amount into base rates less than its projected average fuel costs.

Q. Is the $31.5 million per year actually an undercollection?

A. No. A more accurate description would state that the Company will collect $31.5 million less in base rates, assuming no change in sales, than it would have if a higher amount of fuel costs was rolled-in. A future "undercollection" is certainly not known.

Q. Has the commission previously approved the collection of these costs?

A. No. The Tentative Order specifically said that it "...would not be proper for the Commission to rule, with finality, on the prudence and reasonableness of these undercollections...". The Commission in the Final Order clarified that the Company may "...seek to recover....an amount that represents the difference between the rolled-in rates and a figure that reflects the Company's average fuel costs...", but that both the amount and the recovery should be addressed in the restructuring proceeding.

Q. Has the company put forth the difference between the rolled-in rates and average fuel costs?

A. No. The Company has calculated the 5-year average of its total fuel and purchased power costs over the past five years (Attachment 1, response to OCA I-7). "Rolled-in rates" refers to a unit cost; the Company has not put forth "average" unit costs over the past 5 years in this proceeding. In addition, the PUC Audit Report found that the Company had understated its energy cost recovery by $1,054,000 per year.

Q. Do you think that average unit fuel costs over the past five years are necessarily a good measure of the next two years?

A. No. It appears that unit costs have been decreasing over the last five years, so that the historic average may be higher than most recent experience.

Q. How does the company justify the difference between the rolled-in rates and average fuel costs in this proceeding?

A. The Company attempts to justify its request for $63 million of future undercollections by means of a projection of future energy costs (see response to OCA II-6). This estimation shows a significant increase in Total System Energy Costs from 1997 to 1998, caused entirely by the assumption that revenues from off-system sales decrease. Both MWH sales and revenue per MWH decrease. While I understand that there are some wholesale contracts which will end during this period, a major part of this decrease is projected reductions in the price at which wholesale sales will be made. No evidence has been presented which indicates why the price of sales to PJM would decrease from $20.67/MWH to $10.71/MWH, or why the price to "Other Utilities" will decline by $2.37/MWH. The Company has not adequately demonstrated that fuel and purchased power costs will be higher than the amount "rolled-in" for the next two years. In addition, it has not attempted to demonstrate that it will not be able to trim other expenses enough to make up for any shortfall in energy cost collection that might occur.

Q. What treatment of these dollars are you recommending?

A. The Company has not yet demonstrated that these costs will be unrecovered and prudently incurred. Consistent with Mr. Catlin's testimony, I have excluded the Company's 1997 and 1998 estimate of prospective unrecovered energy costs.

Q. Please describe your recommendation on the lower discount rate to be used in computing net present value.

A. The Company has used a discount rate that incorporates a return on common equity value of 11.5%. This value was authorized by this Commission for PP&L in its last rate case in 1995. More recently, this Commission approved a return on common equity value of 10% for PECO in its May 22,1997 Qualified Rate Order in Docket R-00973877. I have incorporated the more recent 10% value in deriving the discount rate to be used in expressing Mr. Catlin's estimates of regulatory assets and all other components of stranded cost in 1/1/99 NPV terms.

Q. Please describe your recommendation on the PUC jurisdictional percentages to be used in determining stranded costs associated with regulatory assets.

A. In its evaluation of stranded costs, the Company uses PUC jurisdictional percentage allocators to calculate the portion of its total estimated stranded costs that it believes to be subject to the Commission's jurisdiction and therefore eligible for recovery. As shown in Exhibit JRS-1, the Company projects that these percentages will increase over the next several years, adjusting the applicable ratios for known future changes to the Company's existing wholesale contracts (OCA-XI-6).

The resources associated with all wholesale contracts, including those that will be modified in the future, are currently excluded from ratebase (OCA-XI-7). The Company argues that these resources should be eligible for stranded cost recovery because "... under traditional regulation, the applicable portion of capital and operating expenses previously associated with wholesale bulk power contracts would be assimilated into PUC-jurisdictional revenue requirements and corresponding retail customer rates in future rate proceedings as those contracts expire." .

The automatic inclusion of this capacity into jurisdictional rate base is not consistent with past practice of this Commission and it is speculative to assume that costs associated with this capacity would have been recovered under traditional regulation. Moreover, to the extent costs that had been allocated to the wholesale jurisdiction becomes stranded in the future, it is inappropriate to charge these stranded costs to retail customers.

For this reason, we have used the PUC jurisdictional allocation factors, without modification, as approved by the Commission for PP&L in its most recent rate case in the derivation of the regulatory asset stranded costs and all other stranded cost components discussed below. Exhibit RLC-3 presents the allocator values I have used.

Nuclear Decommissioning

Q. What do you believe should be included in stranded costs of the Company's claimed nuclear decommissioning expenses?

A. Mr. Catlin has reviewed the Company's request for unfunded nuclear decommissioning costs and has not recommended any changes to the Company's estimate. I have used these values in my analysis of stranded cost. As discussed above, I apply a lower discount rate and appropriate PUC jurisdictional percentages to these values. I estimate the 1/1/99 NPV of these costs to be $108 million, $15 million lower than the Company's $123 million estimate.

Contracts with Non Utility Generators

Q. Have you reviewed the Company's estimates of cost obligations under contracts with nonutility generators?

A. Yes, I have. The Company has requested $656.9 million (1/1/99 NPV) in stranded costs for its commitments to NUG contracts.

Q. Does the Company's estimate reasonably reflect the expected future costs of these contracts?

A. No, it does not. The Company's estimate overstates these costs in two ways.

First, the Company has based its future cost of power purchases on an unreasonably high forecast of future NUG production. I have revised the forecast of energy to be produced and purchased under these contracts to represent a more reasonable scenario.

Second, the Company has overstated the above-market costs of these contracts by using a low estimate of future market prices. I have revised the estimate of above-market NUG costs by using a more reasonable market price forecast presented by

Mr. Douglas Smith on behalf of the OCA.

With these two adjustments, I estimate the stranded costs associated with the future costs of NUG contracts to be $551 million (1/1/99 NPV), which is $106 million lower than the Company's estimate. This estimate also includes the modifications to the discount rate and PUC jurisdictional allocation factors discussed above. The derivation of my estimate of the NUG contract stranded costs is presented in Exhibit RLC-4.

I address additional considerations of these costs in my discussion of mitigation.

Q. Please explain your revised forecast of energy to be produced and purchased under these contracts?

A. The Company has assumed that all of the NUGs that have not been involved in a restructuring of their contract will operate at a production level equal to the 1994 - 1996 output levels throughout the balance of the contract terms. This produces a high forecast of this production. For most of the NUG projects, the 1994 - 1996 period capacity factors were very high, reflecting the fact that these projects were new, but beyond the start-up phase of their life cycle. This approach produces a forecast that has very little likelihood or possibility to be exceeded by actual performance and has a significant possibility to exceed actual performance. This approach excludes any consideration of the potential for degradation of performance with age or the possibility of extended outages due to technical or other factors.

For example, the Company has assumed that it will be required to purchase 659,688 MWH annually from Gilberton Power ("GP"), one of the largest projects under contract. This is equivalent to an annual capacity factor of more than 95 percent for this 79 MW facility. However, the Company has purchased this amount in only one of the nine years that it has been purchasing power from GP.

Similarly, the Company assumes in its analysis that it will purchase 605,228 MWH annually from Schuylkill Energy Resources ("SER"). However, the Company recently initiated a FERC proceeding to revoke SER's status as a qualifying facility, which could reduce the price and/or volume of purchases the Company is required to make under the current contract.

In light of these specific examples and the other concerns mentioned above, our estimate of NUG contract costs limits the assumed performance of each NUG to an 80% annual average capacity factor for the balance of their contract lives. While lower than the Company's forecast, this assumption still represents a reasonable forecast of production for these projects.

Generation-Related Stranded Costs

Q. Have you reviewed the Company's estimates of generation related stranded costs?

A. Yes, I have. The Company estimated generation-related stranded costs (nuclear and fossil categories) to be $3.57 billion NPV as of 1/1/99. The Company's estimate includes nuclear decommissioning costs, which I have addressed above. When those costs are removed from the generation-related stranded cost, the Company's estimate becomes $3.45 billion.

Q. Are the Company's proposed generation-related stranded costs a reasonable estimate of those costs?

A. No, they are not. My review of the Company's estimates confirms that the $3.45 billion estimate is a substantial overstatement of the Company's generation-related stranded costs. The Company's estimate is based on an inappropriate methodology for computing stranded costs and has a number of problems with inputs and assumptions.

I estimate that the Company has overstated this amount by nearly $4 billion. This means that, in aggregate, there is no stranded cost associated with PP&L's generating plant and that there is net value of more than $500 million that can offset other stranded costs.

Q. Please describe the nature of your concerns with the Company's methodology.

A. The Company uses a revenue requirements approach to develop its estimate of stranded costs. In this approach, they forecast future net above-market costs by subtracting annual revenue requirements based on traditional cost-of-service ratemaking from projected market-based revenues. These values are then discounted, using an after-tax discount rate, to obtain a net present value. The resulting value is the Company's estimate of generation-related stranded costs.

The revenue requirements approach builds into the stranded cost the payments by ratepayers of return on investment and taxes on this return over the life of the plant. It also incorporates other assumptions that are more appropriately considered in the design of the Competitive Transition Charge (CTC). For example, it builds in return on investment over the entire forecast period, ignoring that the CTC period will be a much shorter (7 year) period for recovery of stranded costs authorized by the Commission. PP&L's revenue requirements approach is also flawed by the fact that the Company excluded any consideration of life extension options and of economic retirements..

As I noted earlier, the Company's revenue requirements approach combines the computation of stranded generation-related investment with nuclear decommissioning.

The Company's analysis overstates the NPV of stranded costs because its discounting is inconsistent with its revenue requirements forecast. Its forecasts of revenue requirements and market prices are pre-tax values; they do not include payments of income tax. The Comapny then used an after-tax discount rate to compute the net present value of revenue requirements. This one error causes the Company's stranded cost estimate to be overstated by $880 million, which would reduce its estimate from $4.6 billion to $3.7 billion.

The Company's analysis also uses an unreasonably low forecast of market prices in determining market value and has a number of other problems with input assumptions that inflate the estimate.

Q. What methodology do you recommend for estimating PP&L's generation-related stranded costs.

A. My methodology calculates the difference between the net book value of the generation-related assets as of January 1, 1999 and the estimated market value of those assets as of that date. The stranded investment as of January 1, 1999 resulting from this calculation is then used as the basis for the determination of the CTC charge. This method is very similar to the method used by PECO in its stranded cost proposal and the same method we employed in our recent testimony in the PECO case.

Q. How did you determine the net book value of the generation-related assets as of January 1, 1999?

A. I have estimated the PUC portion of the Company's net book value of generation-related assets as of January 1, 1999 to be $3.25 billion. Exhibit RLC-5 summarizes the PUC net book value that I have estimated for each of PP&L's generating stations.

My estimate of the net book values for total plant, including production plant, general and intangible plant, and land for each of PP&L's generating stations as of January 1, 1999 were based on values presented in PP&L's Exhibit JRS-1. I adjusted these values with appropriate PUC jurisdictional allocation factors to obtain my estimate of PUC jurisdictional net book value.

Q. How did you determine the market value of the Company's generation as of January 1, 1999?

A. The market value of the generating assets is an estimate of the amount a willing buyer would pay for the assets.

The primary component of the market value is the difference between the revenues that a buyer could expect for electric production at market-based prices less the going forward costs of operating the unit, including fuel, O&M, ongoing capital investments, taxes, and administrative and general expenses. I have developed projections of both the going forward costs associated with these assets and the market-based revenues for electric production.

Other factors will also influence the value that a buyer will place on an asset. These factors are discussed further in my discussion of mitigation issues.

Q. **Please describe your estimate of the market-based revenues for the Company's generation.**

A. First, Mr. Smith has developed a forecast of market prices for the PJM system. These market prices are then combined with forecasts of production from each of the Company's generating units to estimate revenues that each unit would realize. These market price and generating unit revenue forecasts are explained in the testimony of Douglas Smith.

Q. **Please describe your estimate of the going forward costs of the Company's generation assets.**

A. The estimated going forward costs for the PUC jurisdictional portion of each generating plant include fuel, operation and maintenance, capital additions, administrative and general costs, and taxes other than income. I have estimated these costs on an annual basis as follows:

<u>Fuel Costs</u> - The annual fuel costs that I assumed for each of the Company's generating units were provided by Mr. Smith and are consistent with the assumptions used in his market price analysis.

<u>Operation & Maintenance Costs</u> - The estimated annual O&M costs for each unit were based on those provided by the Company with several adjustments. First, I adjusted the Company's annual O&M estimates to reflect the different inflation assumptions used in Mr. Smith's market price analysis. Second, I adjusted the estimated annual variable O&M costs to reflect any differences between the projected generation quantities provided by Mr. Smith and Mr. Schadt.

Third, I adjusted the escalation of annual O&M costs after 1997 included by an annual productivity factor of 0.2 percent. The Company's O&M forecast for generation is based on their current budget and plans for the next 5 years, followed by escalation at inflation. These values do not include any further improvements in O&M costs due to competition, as was done by Mr. Jones in his preparation of the Company's market price forecast (in his testimony at 41, he describes the reductions in O&M that have been observed in other industries as they become subject to competition).

Fourth, I excluded certain administrative and general expenses which the Company has allocated to the generation plants. This adjustment reflects the fact that the costs are more closely related to the load aggregation function than to plant operations. This reallocation of A&G is explained in the testimony of Lee Smith. I also corrected an error made by the Company which incorrectly reallocated some of the Company's administrative and general costs to other plants in the future as plants retire, rather than discontinuing the A&G expense associated with the retiring plants.

<u>Plant Additions</u> - The estimated annual plant additions for each unit were based on those provided by the Company, adjusted to reflect the different inflation assumptions used in Mr. Smith's market price analysis.

<u>Taxes Other Than Income</u> - The estimated annual taxes other than income for each unit were based on those provided by the Company for 1997, held constant in the future.

<u>Generating Unit Life</u> - The Company did not include life extensions for any of its units in its analysis. For the Keystone and Conemaugh generating stations, I included life-extension costs and continued operating lives consistent with those estimated by PECO Energy Company, adjusted to reflect PP&L's share of each of the units. For the rest of the Company's units, I reflected the same useful life as that assumed by the Company. This is a conservative assumption.

<u>Fossil Decommissioning Costs</u> - I have excluded all fossil decommissioning costs proposed by the Company.

Q. Please explain why you included life extensions of Keystone and Conemaugh.

A. Our approach to determining generation related stranded cost develops an estimate of the market value of each plant. The primary measure of a generating facility's market value is the NPV of net revenues that can be expected from the facility. PECO correctly identified that these two units added net revenue potential by extending the life beyond its book life through cost effective life extension measures. We included the life extension of these units in our analysis of PP&L's stranded costs because we believe that this value should be included in the analysis and, because they are jointly owned units, we were able to reasonably represent the life extension option at these units with information from the PECO proceeding.

Q. Please explain why you did not include other life extensions.

A. There are several other PP&L units that would appear to be candidates for life extension. The Company excluded all life extensions from its analysis, limiting the information available to us to include other life extensions, as well. This will understate the value of the Company's generating plant and tend to overstate stranded cost.

The Company did not present any analysis indicating that they considered economic retirements of units where the going forward costs exceed market value. The revenue requirements method has all units operating up to the end of their book lives. If any of these units have going forward costs above market value, they should be retired based on economics. Any continued operation of uneconomic units assumed in the analysis will overstate stranded costs.

Q. The company is requesting that it be allowed to include in stranded costs its estimate of what it will cost to decommission fossil fuel units. Do you support this inclusion?

A. No. I have excluded these costs from my going forward costs for the PP&L fossil units. These costs simply do not fit the definition of stranded costs. There is no distinction between a regulatory and a competitive environment that would prevent these costs from being recovered in a competitive environment.

This is also consistent with the Commission's findings in the Company's most recent rate case (Order in Docket No. 00943271C001-C0145 at 106). In that case, the Commission rejected the Company's requested rate treatment for fossil decommissioning.

Q. What are these costs?

A. These costs are supposed to represent the cost of dismantling fossil fuel units at the end of their operating lives.

Q. If it were required that fossil units be dismantled, would this change your opinion?

A. No. In that case, unit owners in a competitive system would also have to dismantle its units. This would be a basic cost of production and would have to be reflected in the market price. The Company seems to be proposing that if ABC Power dismantles a unit, it bear the cost, but if PP&L dismantles a unit, it will have been funded in advance by current ratepayers.

Q. Mr. Catlin has testified regarding the appropriate amount of fossil decommissioning. How does his testimony relate to yours?

A. Mr. Catlin has testified, not that fossil unit decommissioning should be allowed, but that if it is allowed a lower sum of dollars will be adequate to fund it. I agree that if the Commission finds reason to allow fossil unit decommissioning, it should allow the lesser amount recommended by Mr. Catlin, rather than the Company's inflated value.

Q. What net market value for the Company's jurisdictional generation assets did you obtain from this analysis?

A. When we deducted the going forward costs of the generation from the market based revenues and discounted that net margin back to January 1, 1999, the resulting market value for the Company's jurisdictional generation is $3.8 billion. Exhibit RLC-6 shows the contribution each generating plant makes to this total.

Q. Does your recommended methodology produce generation-related stranded costs different from those proposed by the Company?

A. Yes, it does. I estimate that the Company has overstated generation-related stranded cost by $4 billion. This means that, in aggregate, there is no stranded cost associated with PP&L's generating plant and that there is net value of more than $500 million that can offset other stranded costs.

Q. What level of stranded cost results from your methodology and analysis of generation-related, nuclear decommissioning, purchased power, and regulatory assets?

A. With these methodology corrections and modifications to inputs and assumptions, the Company's proposed total level of stranded costs should be $383 million. This value does not reflect impacts of mitigation options available to the Company, as discussed below. My estimates of PP&L's stranded costs are presented in Exhibit RLC-2, including a comparison of each component to the Company's estimates.

Q. How does your estimate compare to the Company's estimate?

A. The Company's filing included a stranded cost estimate of $4.6 billion. My estimate is $ 4.2 billion lower than this value, or less than 10% of the Company's estimate.

Q. How do you explain such a difference in these estimates?

A. The combined effect of the Company's unreasonably low market price forecast and the errors and overstatements built into its revenue requirement methodology produce this result.

Q. Can you provide some perspective that explains why your estimate is reasonable?

A. Yes, I have looked at this in two ways, both clearly leading one to conclude that the Company's stranded cost should be on the order of less than 10% of the Company's estimate.

First, PP&L's rate level suggests that stranded costs should not be high. Mr. Ronald Hill, the Company's mitigation witness, asserts that PP&L's comparatively low rates are a demonstration of PP&L's past mitigation record. He also asserts that "lower rates mean lower stranded costs". While the Company makes the case for its low rates, this did not translate to a low stranded cost forecast by the Company.

PP&L witness Tierney shows that the Company's 1995 average rate, 7.2 cents per kWh, is only 3 mills above the national average, or 4.4%. By comparison, she shows PECO at 9.9 cents per kWh, or 44% above the national average. If Mr. Hill's contention that lower rates (relative to the national average retail rate), mean lower stranded costs, these numbers would suggest that PP&L's stranded cost would be significantly less than PECO's stranded cost, given that the two companies have nearly identical sales levels. However, PP&L's requested $4.2 billion is more than 60% of PECO's stranded cost request of $6.8 billion.

I agree with Mr. Hill's premise and I believe my stranded cost estimate is much more in line with his price comparison than the $4.6 billion presented by the Company.

Another way to put this into perspective is to compare PP&L and PECO on a net asset basis. In 1999, PP&L and PECO generating units are estimated to produce very similar levels of output, 37,500 GWH and 39,900 GWH, respectively. Similarly, the market-revenue value of the generating assets for the two Companies is very close, both in the vicinity of $4.7 billion. Although these two Companies have nearly the same energy production and market energy value, the 1/1/99 net book value of generation assets for PP&L ($3.92 billion) is much lower than PECO ($6.32 billion) and lower than the market revenue value.

It is also important to note that the Company has requested retail customers to fund $3.45 billion in generation-related stranded costs for jurisdictional assets that have a net book value of $3.25 billion, a request for more stranded cost than there is total book value. If the Company's stranded cost request is adopted, the Company would get a multi-billion dollar windfall; first recovering all of its book value through the CTC charge and then earning much more in market-based revenues.

These two simple ways of thinking about reasonable levels of stranded costs for the Company reinforce the results of my in-depth analysis. A company in PP&L's situation should have stranded costs levels well below $1 billion and no generation-related stranded costs. The PP&L requested stranded costs and specifically the requested generation-related stranded costs are significantly overstated.

IV. Stranded Cost Mitigation

Q. What is the Company's obligation to mitigate stranded costs under the Act?

A. The Act establishes clear expectations that utilities will take reasonable steps to mitigate their stranded costs. The Act also allows the Commission to consider past and prospective mitigation efforts by the Company in determining the level of stranded costs to be recovered through the CTC.

The Act places some limitations on the mitigation measures that can be required by the Commission. The Commission cannot require a utility to pursue or transact a buyout, buydown, termination or restructuring of NUG contracts and must allow recovery of any such arrangement that it approves. The Commission can allow, but cannot require, divestiture or reorganization.

The Act places emphasis on the mitigation of generation-related stranded costs. The Act gives the Commission the authority to determine the level of costs to be recovered in this category in consideration of past and prospective mitigation.

Q. Does the Company include stranded cost mitigation in its estimate of stranded cost?

A. The Company's mitigation witness, Ronald Hill, identifies 9 areas of past mitigation and 4 areas of planned mitigation. The net effect of each of these mitigation efforts is included in its derivation of the $4.2 billion stranded cost request. Mr. Hill estimates these mitigation measures have reduced the Company's stranded costs by over $1 billion, meaning that without such measures the Company's request would have been $5.2 billion.

Q. What mitigation measures does the Company include in its proposal?

The past mitigation efforts identified include refinancings of debt, O&M cost control, staffing reductions, inventory reductions, reduced capital expenditures, nuclear cost control, fossil generation improvements, NUG contract changes, and economic development. With the exception of the NUG contract changes, it is not clear how these actions differ from normal, prudent business practice. Mr. Hill offers as his proof of the success of these actions the Company's record of price stability and the fact that their current price positions them just above the national average and better than many others in Pennsylvania. This does not show that the Company has taken maximum advantage of the opportunities available to them.

The prospective mitigation efforts proposed include reductions in capital expenditures, further O&M cost reductions, transfer of depreciation reserve, and absorbing $400 million of the $4.6 billion in stranded cost estimate. Here, the Company's proposals are very limited and largely undocumented. The Company indicates it has no plan for future nuclear cost mitigation or NUG cost mitigation. The transfer of $205 million in depreciation reserve mitigates no cost, it only reallocates costs from competitive generation to regulated T&D.

Q. Please explain your adjustment to net book value for reclassification of nuclear depreciation reserve from transmission and distribution depreciation reserve.

A. The Company reduced the net book value of the Susquehanna SES by $205 million by transferring accumulated T&D depreciation reserves to Susquehanna SES. The Company proposes this transfer as a stranded cost mitigation measure which it claims reduces stranded costs by $317 million. I have excluded this reallocation from my analysis because this is an inappropriate allocation of generation costs to T&D customers, as is described in the testimony of Lee Smith. She has included this change in her analysis of the T&D costs.

This item represents nearly one third of the Company's claimed mitigation. Its estimate of stranded cost, without this reallocation, becomes more than $4.9 billion.

Q. Has the Company met the Act's standards for stranded cost mitigation?

A. No, it has not.

The magnitude of the Company's requested stranded costs ($4.2 billion net of mitigation) is very high, as I discussed above. I do not believe that the mitigation proposed by the Company is commensurate with the magnitude of the request. If the Company's stranded cost amount is authorized, substantial additional mitigation should be required.

However, based on my estimates, the Company's stranded cost is $383 million. The Company's proposed mitigation measures are more commensurate with this level. In fact, Mr. Hill clearly believes that the Company's request is low and his mitigation proposal reflects that belief. If my estimate of stranded cost is authorized, the level of mitigation that would be commensurate with this estimate would be less than under the Company's proposed scenario.

Q. How should the Company mitigate its stranded cost?

A. The Company can meet its mitigation obligation in two ways: first, by reducing the costs of continued operation of producing assets; and second, by reflecting all future value of current assets which have been funded by its customers.

The reduction of costs to enhance net revenues requires the Company to assess several areas of cost reduction, specifically a reduction of production operating expense, maximum possible improvement in the performance of generating units, a maximum feasible attempt to reduce purchased power costs from both utility and non-utility suppliers and purchases of fuels and other inputs to the generation of power, and a plan to retire or sell units which do not have a net positive cash flow under reasonable market assumptions.

The second area of mitigation, that of reflecting full value of assets, is where the Company's case is most deficient. With the exception of its economic development program, Mr. Hill does not incorporate any measures designed to extract more value from its assets. This area includes expanded wholesale and retail marketing of electric services, non-electric utilization of assets, and the sale of assets that have higher market value than value to the Company. I am aware that the Company is active in some of these areas, but Mr. Hill does not incorporate them into his mitigation plan or in his estimate of stranded cost.

Q. Have you included any cost reduction mitigation in your estimate of stranded cost?

A. Only one. I included an adjustment to O&M cost to reflect productivity improvement beyond that assumed by the Company, as discussed above. The Company estimated O&M for individual generating units on the basis of current budgets and plans. However, the subsequent assumption that these unit specific O&M budgets must then increase at the rate of inflation assumes that the Company is unable to find any further efficiencies. We have included in "going-forward" costs the same concept that is now often used in incentive ratemaking, i.e., the increase in O&M expenses will be at a rate of inflation less a productivity factor, which we have set at 0.2%.

Q. What other cost reduction mitigation should be considered?

A. The Company should reflect more aggressive measures in cost reduction at Susquehanna SES and in pursuing further reductions in NUG contract costs, at a minimum.

The Company conducted a strategic assessment of cost control and performance improvement for Susquehanna in 1994 entitled <u>Strategy 2000: Positioning Susquehanna SES For A Competitive Environment</u>. This proprietary document presents an excellent example of an aggressive mitigation plan for the facility. Unfortunately, its recommendations are not reflected in Mr. Hill's proposal, in Mr. Schadt's stranded costs, nor Mr. Jones' market price analysis. If the ratepayers are to be asked to pay the stranded cost levels requested by the Company, cost mitigation such as this should be factored into consideration of allowed stranded cost recovery.

Q. What are the more aggressive measures in cost reduction associated with NUG contracts that should be considered?

A. The Company has indicated in response to discovery (OCA-III-24) that it has no additional mitigation plans for NUG contract costs. Other utilities in Pennsylvania and elsewhere have pursued a number of measures to extract some improvements in NUG contracts. It is important for the Company to view these contracts in the context of the high cost relative to the market of today. While the Company and the Commission may have rightly determined that these contracts were beneficial in the context of the market at the time the contracts were signed, they must now manage these contracts in today's context and pursue any reasonable avenue to reduce the cost of what are now highly costly contracts for its customers. The Company needs to set aggressive goals of cost reduction in this area. Again, if the ratepayers are to be asked to pay the stranded cost levels requested by the Company, cost mitigation such as this should be factored into consideration of allowed stranded cost recovery. While the Commission cannot require NUG contract restructurings, the Company's due diligence in this area must be considered in the context of the magnitude of its overall stranded cost request.

Q. Have any of these cost reduction mitigation measures for Susquehanna or NUG contracts been included in your estimate of the Company's stranded cost?

A. No. I have not incorporated any of these factors in my analysis, nor has the Company included these measures in its estimate.

Q. Please describe the second aspect of mitigation associated with reflecting the full value of the Company's assets?

A. Earlier in my discussion of market value of generating assets, I referred to other factors that will influence the market value of the Company's generation-related assets. These factors include the physical condition of the facility, its operating history, and the potential for cost effective life extension, or repowering. In addition, the existing infrastructure (transmission lines, fuel supply, roads, and land) may increase the value of the assets as a potential site for entirely new generation or other industrial application. The Company's estimate of stranded cost does not include any of these factors.

Another area which must be considered in reflecting full value to the company is risk reduction. The establishment of CTC collection as non-bypassable assessments which will provide not only full recovery of the calculated amounts but in most cases accelerate recovery, lowers the risks to the Company and its investors. Absent these CTC collection provisions, the Company is at risk for underrecovery and disallowance. The Company has proposed no commensurate benefit to its customers in exchange for this risk reduction. In fact, this feature of restructuring will allow the Company greater ability to secure financing and reinvest in other ventures to its financial benefit without any compensation to the "underwriters" of that benefit. It is especially important to note that a transfer of merely the financing and income tax savings to the customers is insufficient compensation to the financing burden being underwritten. The Company ultimately lowers its revenue requirement through a portion of actual cost reduction but retains the benefits of the lower debt levels, lower risk, improved balance sheet and cash infusion. I propose to recognize this value as a mitigating factor to the otherwise uneconomic asset recovery guarantees.

This risk reduction would be extreme under the Company's proposal, as the retail customers would see no material rate reduction for 7 years, while the Company would garner more than the full value of its generating assets through the CTC and go into the competive market with no risk. Under my proposal, the risk is more balanced, with retail customers seeing lower rates and the Company getting fair value and opportunity to participate in the competitive market.

A final item in mitigation of the Company's proposed stranded costs is the value of the enterprise retained by PP&L. Traditionally, the customer received benefits from this on-going value of the utility company to the extent that it produced value or secured cost reductions. Post restructuring, the Company is left with a going concern value of significant proportions. This value has been created by its long term monopoly standing and funded by its customers. It now has the ability and means to market this value, again with no compensation to its customers. It is obvious, if not completely quantifiable, that there is great value inherent in PP&L's name, its customer base, and its ability to maintain significant market share within its traditional territory as well as in other areas and its corporate infrastructure. Any competing entry into this Pennsylvania utility market must be prepared to incur tremendous expenses to secure a market position. We note also that this market position will enable the going concern to expand into a variety of other energy-related and entirely distinct ventures. The value of these opportunities is continually recognized in the marketplace by increases in stock value when T&D systems are spun off or when the riskier generation business is financially secured through governmental or regulatory action. This key market position of PP&L has resulted from its monopoly and now PP&L is requesting its transfer to stockholders free of cost. This is unacceptable, particularly in light of PP&L's request for billions of dollars of stranded cost recovery guarantees.

Q. Why do you define the market value of generation related assets as the amount a willing buyer would pay for the assets?

A. Although the Company is not proposing to sell these assets, this transaction has the same effect as an outright sale on the PP&L franchise ratepayers. Under the restructuring plan, certain rights and obligations will undergo fundamental change. The effective ownership of generation assets and risks of operation will shift to unregulated operations of the Company.

Under traditional regulation, a gain on an asset was considered as a cost item in ratemaking. If a utility sold an asset at a price above its net book value, the gain after taxes was recognized as a reduction to its electric revenue requirements.

After restructuring is complete, the utility is the owner of each generation-related asset and is the beneficiary of any subsequent gain. Thus, the residual value of each asset is no longer inconsequential. If the residual market value is ignored, the ratepayers will have, in effect, sold the assets to the utility below market.

The valuation of any asset is the sum of its net earning ability and its residual value. The Company has put forth estimates of negative residual value and on-going liability with, for example, its nuclear units. Many hydro and fossil units, on the other hand, will have significant value well past their book life.

Q. Could you provide an example which indicates why there may be more value in the generation assets than the net margin to be earned from them?

A. Yes. One source of value will be the sites on which generation units are located, which are supplied with transmission access, with transportation of fuel, and with appropriate zoning. In the case of dams, the sites have permits to generate. Some sites are located in the more congested regions of PJM, providing them with additional value.

Q. Have you estimated the possible value of generating sites?

A. I have developed a "barebones" type of estimate. While it is difficult to determine an exact value for mitigation, it is clear that some mitigation is possible. I have estimated the current value of the bare land, although this will significantly understate value. I simply determined the number of years since the unit was constructed, assumed that this was the year the land was acquired, and escalated the book value by 4% annually to 1999. Since land has generally escalated at much higher rates, this estimate is very conservative. My total market value of generating plant includes $66 million to reflect the inflation-adjusted cost of land at each station. Exhibit RLC-6 shows how I have incorporated this into market value.

Q. Please summarize your view of mitigation.

A. In summary, mitigation must be evaluated in the light of the practical cost reduction and revenue enhancing areas as well as the harder to quantify value transfers. While the Company has claimed that it has reduced some small amount of costs, it has not addressed the more significant areas of mitigation - the offsetting value of the assets and going concern being transferred to the Company and its stockholders. In that transfer, the traditional return of benefits to the customers is eliminated. The argument of the level of stranded cost recovery absent the identification of new customer risks and new Company value is incomplete. The most effective way to address these mitigation values, however, is not in quarreling about their exact numerical value but rather as a rational basis for sharing of costs and benefits of restructuring between the customers and investors of the Company.

V. Sharing of Stranded Cost between Stockholders and Ratepayers

Q. What provisions are included in the Act for allocation of stranded costs between shareholders and ratepayers?

A. The Act contemplates that the Commission will determine the level of stranded costs that the Company can collect from ratepayers through a CTC. With respect to utility owned generation, the Act does not mandate full recovery of stranded costs. A just and reasonable sharing of these costs must be determined by the Commission.

Q. How has the Company proposed that stranded costs be shared?

A. The Company's proposal calls for the shareholders to absorb $401 million of its estimated $4.6 billion in stranded cost. This is the amount that the Company would be unable to collect through a 7 year CTC under the rate cap.

Q. What is your proposal for the sharing of stranded utility-owned generation costs in the context of the Company's stranded cost estimate?

A. The Company's approach is unacceptable in light of the magnitude of its request. It is inconsistent with past ratemaking policy in Pennsylvania, which has not allowed a return on plant which was not used and useful. Stranded generating plant is not used and useful; it is not providing benefits to ratepayers. Stockholders, who have been in a position to influence the Company's past investments, and who have benefited from profitable investments, should bear some of the cost of stranded investments. Costs will be shared if the Commission does not include a return on stranded costs in the CTC that will be paid by ratepayers. It is my position that if the Commission finds that PP&L has net stranded generation costs, the Company should be permitted to receive recovery of those costs over the seven year period, but should not be permitted to charge ratepayers a return on those costs.

Q. Are you arguing that the company should not be allowed to earn a return on its generating assets?

A. No. Denial of a guaranteed return on stranded generating assets through a CTC does not deny the Company a return; the Company still has the ability to earn a return through its future actions. The Company may improve margins from plant, sell plant to buyers with a higher projection of future market prices, sell sites, or use existing sites to build additional generation.

The Company has the ability to use its expertise in the generation business in a number of ways. The ability to conduct various nonregulated businesses has been acquired with the support of ratepayers. PP&L currently markets power in other regions. The Company has two unregulated subsidiaries: 1) Spectrum Energy Services Corp, which markets energy related services and products; and 2) Power Markets Development Co., which invests in energy projects worldwide. All of these sources of income exist because of expertise that has been acquired while functioning as a regulated generating utility, and would not have been possible if the Company had not had a production function.

Providing investors with a recovery of stranded plant through a CTC but no return on this plant more appropriately balances risks and rewards to investors and ratepayers.

Q. **Does the sharing of uneconomic costs balance risks and competitive opportunity?**

A. Yes, there are clear opportunities for investors that will improve in a competitive generation market. For example, stockholders will reap all future benefits of generation assets which have not been fully captured in the original estimate of margin revenue. In the future, the Company will enjoy full rights to any value which these assets may have. In the traditional regulatory regime, if a depreciable asset was sold, any net sale proceeds would be returned to ratepayers. Thus, the advent of generation competition actually implies a transfer of ownership of these assets from customer to investor. The Company has asserted that it has estimated the value of these plants and taken that into account in the stranded cost calculation. This estimate, however, assumes that the only value of the assets is the revenue that they will earn if the Company's estimate of future market prices is accurate. There are other potential areas of value that must also be considered. Further, traditional regulation has maintained that a sharing of risk and benefit is required for just and reasonable rates.

Q. What is your proposal for the sharing of stranded utility-owned generation costs in the context of your stranded cost estimate?

A. My estimate of PP&L's stranded cost is substantially lower than the Company's estimate and includes a positive net market value of the generation plant. I believe the overall magnitude of stranded cost included in my estimate is reasonable under the circumstances. In this context, there is no net stranded generation plant, making the denial of return on plant which is not used and useful moot. I recommend that the net value in the generating plant be used as an offset to stranded costs associated with NUG contract costs and regulatory assets, with the balance to be recovered through the CTC.

However, if the Commission finds the Company does have net stranded generation costs, then I would recommend that the Company be permitted to recover those costs on a levelized basis over the CTC period, with no return on those costs.

VI. Recommendations on Stranded Cost Recovery

Q. Please summarize the stranded cost recovery you are proposing.

A. PP&L should be allowed to recover $382.6 million in net stranded costs (1/1/99 NPV) through a CTC charge. As shown in the Testimony of Lee Smith, this results in a CTC charge that will lower rates in the 1999 to 2005 period and allow the competitive generation market to operate within the rate cap. This also allows full funding of the nuclear decommissioning fund for Susquehanna.

For the many reasons stated above, the Company should not be allowed to recover its requested $4.2 billion stranded costs. If the Company's stranded cost were adopted, significant adjustment for mitigation and cost sharing should be implemented to reduce the amount to be paid by ratepayers, including the denial of any return on stranded generating costs.

Q. In the company's previous rate case, the company requested a modification of its Susquehanna depreciation. In addition, it indicated that depreciation expense and the Company's overall rates would drop by $90 million in 1999. Are you recommending any adjustment for this decrease in depreciation expense?

A. If the Commission supports the stranded cost amount which I have recommended, customers will receive more of a decrease in 1999 than would have been caused by the decrease in the depreciation expense. Thus, this issue would be moot. However, under no circumstances should customers pay rates in 1999 that reflect the depreciation rate that is embedded in current rates. If the Commission supports a higher stranded cost collection in 1999, it should at the same time reduce the Company's rates by the amount that reflects the reduction in depreciation expense and rates that was promised to customers.

Q. Does your proposal reflect the securitization of any stranded costs?

A. No. Like the Company's own filing in this case, I have made no provision for securitization at this time. I agree with Mr. Hill's assessment that this is better left for consideration following resolution of the issues in this proceeding.

Q. Does this conclude your testimony?

A. Yes it does.

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Exhibit RLC-1

RICHARD LA CAPRA

LA CAPRA ASSOCIATES
Principal

Mr. La Capra has over twenty-five (25) years of experience in project management for utilities and energy intensive industries. In his career, Mr. La Capra has served over fifty (50) domestic and foreign clients. Mr. La Capra is currently the Principal in charge of La Capra Associates.

Mr. La Capra's professional accomplishments include:

- Experienced expert witness having testified before numerous State and Federal bodies in the areas of pricing policy, cost analysis, cost of money, load and customer research, financial feasibility, and power supply requirements.
- Principal advisor to Massachusetts Division of Energy Resources, to New Hampshire Legislature, and to Rhode Island Division of Public Utilities on electric industry restructuring.
- Consultant to numerous public and private utilities in the areas of ratemaking, power supply planning, negotiation of contracts, and development of wholesale rates.
- Principal Consultant to the Electric Power Research Institute in the areas of electric utility costing and ratemaking, and author of three (3) research topic papers for the National Association of Regulated Utility Commissioners.
- Consultant to the World Bank (IBRD) in the areas of pricing and subsidy policy for National Electrification loans.
- Project Manager for National Tariff Studies in Costa Rica, El Salvador, The Kingdom of Saudi Arabia and the Liberia Electric Company.
- Developer of widely used methodologies and software for accounting and marginal cost of service analyses.
- Managed developmental load research programs in six mid-western and eastern states.

- Developed and presented professional development programs for the Electric Council of New England, the Center for Professional Advancement, the New England Rate Forum, the Electric Power Research Institute, the American Gas Association and the University of Missouri.

- Supervised short and long term power transactions among NEPOOL members and negotiated power contracts for NEPOOL utilities with outside utilities.

- Supervised and sponsored resource plans for both utilities and cogenerators before the Massachusetts Energy Facilities Siting Council.

- Technical member on demand side management Collaborative committees in Massachusetts and Vermont.

- Technical advisor to New York City in establishing its energy office and public utility service.

- Managed the analyses and sponsored valuation assessment of utility distribution and production property from income and market bases both utilities and municipal governments.

- Assisted in the financial reorganization of a cooperative utility, including restructuring $100 million of debt and reconfiguring its power supply assets and contracts.

- Sponsored phase-in approaches for new production plants in Kansas and Missouri (Wolf Creek), North and South Carolina (Maguire), and Montana (Colstrip 2).

- Directed feasibility studies assessing privatization potential for publicly owned facilities.

- Technical advisor for cooperative utilities in assessing the economics of Hydro Quebec phase II purchase and subsequent Hydro Quebec power purchases.

- Economic advisor to the City of Boston in the development of hackney carriage rates and the establishment of a market based number of hackney medallions.

- Negotiated transmission contracts, wheeling rates, and distributions leases for a number of utilities and independent power producers.

A representative listing of the clients Mr. La Capra has served include the following:

Altresco Financial Corporation
City of Ames (Ia)
Anaconda Minerals Corporation
Berkshire Gas Company
Boston Edison Company
The City of Burlington (Vt)
The City of Boston
Cabot Power Corporation
Connecticut Municipal Electric Cooperative
Colonial Gas Company
Duke Power Company
Electric Power Research Institute
Essex County Gas Company
InterAmerican Development Bank
Iowa Electric Light & Power Company
Kansas City Power & Light Company
Littleton Water & Light Department
Mobile Gas Service Company
Massachusetts Electric Company
Montana Power Company
Nantucket Electric Company
New Hampshire Electric Cooperative
Northeast Utilities
Providence Energy Corporation
City of Plattsburgh (NY)
Town of Reading (Ma)
City of San Antonio (Tx)
Sierra Pacific Power Company
Standard Oil of Ohio Company
City of Tacoma (Wa)
United Illuminating Company
Vermont Electric Generation & Transmission Cooperative
Washington Electric Cooperative
World Bank

Mr. La Capra has previously served in the following professional capacities:

- Manager of the Rates, Financial Services and Utility Management Consulting Groups for **CHARLES T. MAIN, INC.**
- Rate and load research supervisor for the **AMERICAN ELECTRIC POWER SERVICE CORPORATION**
- Planning Engineer for the **PENNSYLVANIA-NEW JERSEY-MARYLAND POWER POOL**

EDUCATIONAL BACKGROUND:

- Bachelor of Engineering: Electrical and Mechanical Engineering, **STEVENS INSTITUTE OF TECHNOLOGY**
- Masters of Business Administration: Economics, **FAIRLEIGH DICKENSON UNIVERSITY**
- Certificate in Advanced Finance: **NEW YORK UNIVERSITY**

Pennsylvania Power & Light

Summary of PUC Stranded Costs as of January 1, 1999 ($000)

	OCA	Exh. JRS-1	Difference	% Diff.
Net Generating Plant	$3,248,442	N/A	N/A	N/A
Less: Market Value	($3,784,172)	N/A	N/A	N/A
Plus: Fossil Decommissioning	$0	$320,489	($320,489)	*-100.0%*
Stranded Generating Plant	($535,730)	$3,446,523	($3,982,253)	*-115.5%*
Regulatory Assets	$259,249	$383,911	($124,662)	*-32.5%*
NUG Contracts	$550,951	$656,870	($105,919)	*-16.1%*
Nuclear Decommissioning	$108,125	$123,657	($15,532)	*-12.6%*
Total Stranded Cost	**$382,595**	**$4,610,961**	**($4,228,366)**	***-91.7%***

Pennsylvania Power & Light

PUC Jurisdiction % for Plant in Service from 1995 Ratecase

	Nuclear	Wholly Owned Coal	Other Non-Nuclear	Safe Harbor	NUG Purchases
Total	$4,068,284	$1,491,002	$725,159	$9,845	$229,157
Atlantic City	$0	$51,022	$0	$0	$0
Jersey Central	$455,038	$166,769	$81,109	$0	$0
Baltimore G&E	$268,506	$0	$0	$0	$0
Net Electric	**$3,344,740**	**$1,273,211**	**$644,050**	**$9,845**	**$229,157**
Transmission	$72,944	$27,767	$14,046	$215	$4,689
Primary	$22,327	$8,499	$4,299	$65	$1,476
UGI	$57,639	$21,941	$18,345	$170	$3,179
Net PUC	**$3,191,830**	**$1,215,004**	**$607,360**	**$9,395**	**$219,813**
Percent of Total					
Total	100.000%	100.000%	100.000%	100.000%	100.000%
Atlantic City	0.000%	3.422%	0.000%	0.000%	0.000%
Jersey Central	11.185%	11.185%	11.185%	0.000%	0.000%
Baltimore G&E	6.600%	0.000%	0.000%	0.000%	0.000%
Net Electric	**82.215%**	**85.393%**	**88.815%**	**100.000%**	**100.000%**
Transmission	1.793%	1.862%	1.937%	2.184%	2.046%
Primary	0.549%	0.570%	0.593%	0.660%	0.644%
UGI	1.417%	1.472%	2.530%	1.727%	1.387%
Net PUC	**78.456%**	**81.489%**	**83.755%**	**95.429%**	**95.922%**

Source: Exhibit JMK-1.

Pennsylvania Power & Light

Stranded Costs Associated with NUG Purchases

2000		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total NUG Capacity (MW)		366.4	366.4	366.4	366.4	354.4	354.4	354.4	354.4	354.4	250.6	169.9	15.3	5.3	5.3	5.3	5.3
Average Capacity Price ($/kW-yr)		$19.73	$30.43	$41.67	$43.12	$44.20	$45.66	$47.12	$48.91	$50.38	$52.19	$54.02	$56.18	$57.96	$60.12	$62.29	$64.47
Total Capacity Revenue		$7,229	$11,149	$15,267	$15,798	$15,663	$16,181	$16,698	$17,333	$17,863	$13,091	$10,257	$867	$304	$316	$327	$338
Total NUG Purchases (MWh)		2,408,830	2,408,830	2,408,830	2,408,830	2,396,030	2,396,030	2,396,030	2,396,030	2,396,030	1,672,410	1,245,214	106,872	36,792	36,792	36,792	36,792
Average Energy Price ($/MWh)		$22.35	$23.61	$25.14	$26.38	$28.14	$29.42	$31.84	$34.12	$36.01	$38.30	$39.64	$42.34	$44.06	$46.14	$48.02	$50.28
Total Energy Revenue		$53,837	$56,872	$60,568	$63,545	$67,481	$70,550	$76,363	$81,821	$86,353	$64,053	$49,360	$4,526	$1,621	$1,698	$1,767	$1,850
Total Market Revenue		$61,066	$68,021	$75,825	$79,343	$83,144	$86,731	$93,061	$99,153	$104,207	$77,144	$59,617	$5,392	$1,925	$2,013	$2,094	$2,188
Total Cost of Purchases																	
Purchases		$154,995	$154,995	$154,995	$154,995	$154,120	$154,120	$154,120	$154,120	$154,120	$109,509	$81,314	$6,833	$2,206	$2,206	$2,206	$2,206
Buyout Payments		$20,732	$20,732	$19,974	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost		$175,728	$175,728	$174,970	$154,995	$154,120	$154,120	$154,120	$154,120	$154,120	$109,509	$81,314	$6,833	$2,206	$2,206	$2,206	$2,206
Total Excess/(Deficiency)		($114,662)	($107,706)	($99,145)	($75,652)	($70,976)	($67,390)	($61,069)	($54,967)	($49,914)	($32,365)	($21,697)	($1,451)	($282)	($194)	($114)	($18)
PUC Jurisdiction %		95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%	95.922%
PUC Excess/(Deficiency)		($109,966)	($103,314)	($95,102)	($72,567)	($68,082)	($64,641)	($58,579)	($52,726)	($47,876)	($31,045)	($20,812)	($1,392)	($271)	($186)	($109)	($18)
Discount Factor	7.24%	1.0362	1.1112	1.1917	1.2780	1.3705	1.4697	1.5761	1.6902	1.8126	1.9438	2.0845	2.2355	2.3973	2.5709	2.7570	2.9566
NPV PUC Excess/(Deficiency)		($106,143)	($92,973)	($79,806)	($56,784)	($49,676)	($43,983)	($37,167)	($31,195)	($26,414)	($15,971)	($9,984)	($623)	($113)	($72)	($40)	($6)
Total NPV PUC Excess/(Deficiency)		($550,961)															

Pennsylvania Power & Light

Net Book Value of Generation Plant as of January 1, 1999 ($000)

	Production Plant	General & Intang. Plant	Land Cost	Total Plant	PUC Jurisdiction	PUC Total Plant
Nuclear Plant						
Susquehanna	$2,729,381	$68,619	$8,630	$2,806,630	78.456%	$2,201,970
Fossil Plant						
Brunner Island	$300,518	$16,042	$2,540	$319,100	81.489%	$260,031
Holtwood 17	$18,008	$961	$213	$19,182	81.489%	$15,631
Holtwood Hydro	$66,328	$3,541	$1,627	$71,496	83.755%	$59,881
Martins Creek Coal	$102,016	$5,446	$3,940	$111,402	81.489%	$90,780
Martins Creek Oil	$209,826	$11,201	$0	$221,027	83.755%	$185,121
Montour	$269,633	$14,394	$4,630	$288,657	81.489%	$235,224
Sunbury	$120,024	$6,407	$1,271	$127,702	81.489%	$104,063
Wallenpaupack Hydro	$8,284	$442	$2,551	$11,277	83.755%	$9,445
Keystone	$27,778	$1,483	$576	$29,837	83.755%	$24,990
Conemaugh	$57,687	$3,079	$444	$61,210	83.755%	$51,266
CTG	$11,300	$603	$83	$11,986	83.755%	$10,039
Total Fossil	**$1,191,402**	**$63,599**	**$17,875**	**$1,272,876**	**82.213%**	**$1,046,473**
Total Generation	**$3,920,783**	**$132,218**	**$26,505**	**$4,079,506**	**79.628%**	**$3,248,442**

Pennsylvania Power & Light

Estimated NPV Contribution Margin ($000)

$000	*NPV as of 1/1/99*
Nuclear Plant	
Susquehanna	$825,650
Fossil & Hydro Plant	
Brunner Island	$567,512
Holtwood 17	$4,983
Holtwood Hydro	$158,208
Martins Creek Coal	$103,410
Martins Creek Oil	$112,645
Montour	$723,553
Sunbury	$67,815
Wallenpaupack Hydro	$19,670
Keystone	$114,780
Conemaugh	$148,898
CTG	$26,851
Safe Harbor Hydro	$76,978
Total Fossil & Hydro	**$2,125,303**
Total NPV Margins	**$2,950,953**
Inventory & Working Capital	($92,588)
Future Tax Depreciation Benefits	$0
Accum. Deferred ITC Benefits	$65,020
Deferred Income Tax	$794,699
Total Adjusted NPV Margins	**$3,718,083**
Inflation Adj. Land Value	$66,089
Total Market Value	**$3,784,172**

OCA STATEMENT NO. 1- S

8/29/97
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

w/ exhibits
RLC-7 to
RLC-10

APPLICATION OF PENNSYLVANIA :
POWER & LIGHT COMPANY FOR :
APPROVAL OF ITS RESTRUCTURING :
PLAN UNDER SECTION 2806 OF THE :
PUBLIC UTILITY CODE :

DOCKET NO. R-00973954

SURREBUTTAL TESTIMONY

OF

RICHARD LA CAPRA

On Behalf of:
OFFICE OF CONSUMER ADVOCATE

AUGUST 1997

SURREBUTTAL TESTIMONY OF RICHARD LA CAPRA

Q. MR. LA CAPRA, PLEASE IDENTIFY YOURSELF FOR THE RECORD.

A. My name is Richard La Capra and my business address is 333 Washington Street, Boston, MA 02108.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS PROCEEDING?

A. Yes, I have previously submitted direct testimony in this proceeding.

Q. WHAT IS THE FOCUS OF YOUR TESTIMONY?

A. I would like to respond to the various claims of Pennsylvania Power & Light Company ("PP&L") witnesses regarding the reliability of their methods for valuing stranded costs and the subsequent financial impact on the Company. In summary, the Company believes that our computations of stranded costs yield too low a value and would consequently cause financial harm to the Company.

Q. WHAT IS YOUR RESPONSE TO THESE ASSERTIONS?

A. The Company's belief that its stranded costs are higher than we calculated is based on an unrealistically low projection of market price, an undervaluing of its mitigation potential and the real future value of its assets and its claim of a right to a full rate of return on stranded assets.

First, the Company's market price projections are unrealistically low. They are based on fuel price expectations lower that other forecasts and have other methodological problems as is described by Mr. Smith.

Next, the Company has taken great pains to argue a regulatory valuation approach. We assert that an asset valuation is the proper methodology and that an appropriate use of discount rates and timing of revenues and expenses will result in the level of stranded cost, when adjusted for new market prices, as proposed in our direct testimony.

Last, the financial harm claimed by Mr. Schadt is not supportable. PP&L would experience smaller pre-tax earnings not as a result of the OCA proposal for CTC recovery, but as a result of earlier year market prices being lower than early year generation costs. In fact, the Company's own proposal would show a similarly gloomy picture as that of the OCA. The situation is reversed in later years as market prices increase relative to PP&L's costs. If, however, the Company believes that a levelized annual CTC recovery will cause undue financial stress, a reasonable solution might be to reshape the annual collection of stranded cost during the transition period. This issue is addressed in the Surrebuttal Testimony of OCA witness Lee Smith.

Fuel Cost Projections and Market Price

Q. WHAT FUEL PROJECTION DOES THE OCA RECOMMEND IN THE CALCULATION OF STRANDED COSTS?

A. The OCA recommends using a current and common fuel projection for each of the restructuring filings absent any region specific permanent differences. The Fall 1996/Winter 1997 forecast provided by DRI for the PECO filing was used as a basis to calculate market prices in their proceeding and was used in my orginal testimony in this proceeding. PECO has offered a lower DRI forecast updated in the Spring 1997 in its rebuttal testimony.

We have shown the impacts of both the DRI Fall 1996/Winter 1997 fuel price forecast, prepared by DRI and used in the filing of PECO Energy Company, and DRI's more current Spring 1997 values. The more current DRI base case fuel cost projection should be reasonable for this proceeding. For reasons of symmetry which I discuss later, it would be important to consider the range of forecasts which the OCA has presented in this proceeding, as well as the range of uncertainty with regard to those forecasts.

Q. GIVEN THE NUMBER OF DIFFERENT FUEL ESTIMATES BEING PRESENTED IN THESE CASES, WHAT WOULD BE A REASONABLE APPROACH TO SELECTING AN ESTIMATE?

A. A reasonable balance between PP&L and its customers must be established since the use of some estimate is unavoidable. The determination of stranded costs, however, should be based on a market price forecast which considers the Company's ability to file for exceptions to the rate cap for significant changes in the unit price of fuel that prevent the utility from earning a fair return. The transition period, however, does not provide for rate reductions if future circumstances are fortuitous for the Company.

There appears to be adequate protections for the Company; consequently the basis for the fuel cost estimates and stranded cost should protect the customer, i.e., a more robust market price estimate and lower stranded cost estimate within a "range of reasonableness" would balance the risks and rewards between Company and customer. At a minimum, as I discuss below, the Company should not be permitted to earn a return on stranded generating assets in addition to the recovery of such costs that would result from a higher stranded cost estimate.

Q. PP&L WITNESS KAHN ASSERTS THAT YOUR MARKET PRICES CONTRADICT HISTORICAL FORCES AND THE VERY EXPECTATIONS OF MAJOR BENEFITS OF COMPETITION TO CONSUMERS. WHAT IS YOUR RESPONSE TO THAT CLAIM?

A. First, Mr. Kahn admits that he has not reviewed our analysis or results. He relies on discussion's with PP&L's market price witness as the basis for his conclusions. If he had done such review, he would find that our price forecast is not contradictory to his expectations.

For example, he cites average generating costs in the range of 6-10 cents and contrasts that with new combined cycle costs in the range of 4 cents. Our market price forecast is below 4 cents through 2006 and does not reach 6 cents. In all years, our prices are well below the current average costs cited by Kahn, even including consideration of inflation.

While our forecast is high relative to PP&L's very low forecast, it is very consistent with general expectations that generation costs in the future will be significantly lower than have been experienced in the past.

Q. PP&L WITNESS KAHN HAS ASSERTED THAT YOUR ESTIMATE OF STRANDED COSTS DOES NOT PROVIDE THE SYMMETRY REQUIRED BY THE LEGISLATION. WHAT IS YOUR VIEW OF THE SYMMETRY ISSUE?

A. Mr. Kahn is correct that concerns about symmetry are important, but he is wrong in his analysis.

First, Mr. Kahn assumes that PP&L has no recourse if the Commission sets stranded costs too low. In fact, the legislation maintains specific provisions which allows the Company to seek relief if this is, in fact, the case.

Second, Mr. Kahn contends that the rate cap limits the Company's opportunity if stranded costs are set too high. This ignores the fact that, while there may be some delay in the Company's collection of the overstated stranded costs, the Company also obtains substantial generating assets for virtually no cost to operate in a market that has market prices much higher than those used as a basis for establishing stranded costs. While Mr. Kahn may believe PP&L is harmed in this scenario, the Company, in fact, could end up with a significant windfall if stranded cost recovery is set too high. In contrast, the consumers pay higher stranded costs in the transition period and higher market prices in the ensuing competitive market.

This asymmetry of impacts make it very important for consumers that the Commission take care to set stranded costs at reasonable projected values.

Computation of Stranded Costs

Q. DO YOU HAVE ANY CHANGES OR CORRECTIONS TO THE COMPUTATION OF STRANDED COSTS PRESENTED IN YOUR PRIOR TESTIMONY?

A. Yes. Mr. Smith describes changes to his forecast of market prices in his surrebuttal testimony. Consistent with these changes, I have revised my estimate of PP&L's stranded cost. The net effect of Mr. Smith's changes results in an increase in the stranded cost estimate by $149 million.

In all other respects, my testimony on methods, assumptions and results remains the same as originally filed. A summary of my revised stranded cost estimate of $532 million based on these adjustments is presented in Exhibit RLC-7.

I have also estimated PP&L's stranded cost based on the market prices projected by Mr. Smith consistent with the Spring 1997 DRI fuel price forecast. Using this slightly lower market price projection, I would expect PP&L's total stranded costs to be approximately $1.08 billion, an increase of $548 million.

Under this lower market price forecast, I would estimate a net stranded cost of $138 million associated with PP&L's generating assets. As I discuss in my direct testimony, I believe that the Company should not be allowed to charge ratepayers a return on the stranded generation costs through the CTC. This represents a reasonable method of sharing the stranded costs between ratepayers and shareholders. Rather than allowing a return both of and on (grossed-up for taxes) the stranded generating plant, the Company should be allowed only a recovery of the stranded generating cost through the CTC, as represented in Ms. Smith's Exhibit LS-8. As I stated in my direct testimony, with respect to generating assets under Section 2803(c)(3) of the Act , even if costs are found to be stranded, the Commission must determine whether recovery from ratepayers would be just and reasonable.

I recommend that a reasonable sharing of such costs would be to allow recovery of, but no return on, such costs during the transition period.

Q. IS THE COMPANY REQUIRED BY THE ACT TO COMPUTE STRANDED COSTS BY THE "REGULATORY METHOD"?

A. No, the Company is not required to compute its stranded costs by the regulatory method, nor is this method the only approach consistent with the Act. The Act requires the computation of the level of costs that would (are) being recovered under traditional regulation but would not be recoverable in a competitive market. This is simply a mandate to calculate above market cost and the most direct way to do that is to find the difference between non-mitigatable fixed cost for each generation asset and the price a willing buyer would pay for the asset. This is the traditional valuation problem not some new "complex alternative procedure" as Mr. Schadt characterizes it. In fact, the traditional valuation is far more intuitive than the morass of regulatory calculations. One can be sure that the non-utility buyers of generating assets are using traditional valuation methods, i.e, looking at the sum of operating income and going concern value of the asset(s) to determine their bids, rather than studying up on traditional regulatory theories. The regulatory approach can cloud many important issues such as running plants that are not economical, including going forward costs or not extending plants lives where it may be economical. The implicit assumptions in the regulatory approach are that the Company receives perfect rate relief, has no regulatory lag and earns precisely its full allowed rate of return every year.

Q. DO THE METHODS YIELD DIFFERENT RESULTS?

A. In most cases they are likely to yield different results if for no other reason than market value, in fact, incorporates more opportunities than regulatory revenue requirements. In theory, however, if one ideally simulates the revenue requirement calculations to mimic the value to a competitive buyer, then the values are apt to be close. There should not, however, be this artificial and unnecessary constraint to bend the regulatory model to describe competition; rather begin with a competitive model.

Q. MR. HILL HAS CHARACTERIZED YOUR ESTIMATE OF PP&L'S STRANDED COSTS AS "SHOCKINGLY INADEQUATE". PLEASE EXPLAIN WHY YOU BELIEVE YOUR ESTIMATE IS REASONABLE IN LIGHT OF THE COMPANY'S MUCH HIGHER ESTIMATES AND EXPECTATIONS.

A. As I pointed out in my original testimony, PP&L's estimate of stranded costs, particularly its estimate of generation related stranded costs, is grossly out of line with the Company's total book value and current price level. For example, PP&L has asked for \$3.45 billion in generation stranded costs which is more than the entire \$3.25 billion January 1999 book value of the Company's generating assets. The implication is that its generation currently has negative value in the market, a proposition that I find very hard to believe, indeed, shocking.

The Company's use of its regulatory model of estimating stranded costs has led it to believe this strange result. If nothing else, our asset valuation method produces the results in a form that allows this type of reality check on the results.

I should point out, that the only other rigorous attempt to estimate PP&L's stranded costs, presented by PPLICA, has a result very similar to mine, and very different from the Company's.

Q. **MR. GUTH HAS TAKEN ISSUE WITH YOUR USE OF THE ASSET VALUATION APPROACH, ASSERTING THAT THERE IS NO VERIFIABLE LINK TO ACTUAL MARKET VALUE OF THE PP&L ASSETS. HOW DO YOU RESPOND?**

A. Mr. Guth clearly has not been following recent market activity in New England and elsewhere. Mr. Guth presents a number of theoretical arguments on buyer behavior relative to discounted cash flow estimates which are inconsistent with recent experience in the market for generation assets. He also seems to be unaware of the activity of Pennsylvania utilities in the market for generating assets.

While, Mr. Guth asserts that my market price and stranded cost estimates are not grounded in the market, there is recent and directly relevant experience in New England. My recent work on market price forecasting in New England has been criticized by experts such as Mr. Guth for being too high. However, New England Power Company just recently completed the sale of nearly 4,000 MW of generating assets to U.S. Generating Company for almost $1.6 billion; a price that well exceeded estimates made by myself and others, and exceeded the book value of their assets by almost 50 percent. New England Power attracted serious interest from more than 25 bidders for their assets. Also in two recent solicitations by large consumers for suppliers under retail access in Rhode Island and Massachusetts, the price bid received exceeded the customers' options for standard offer prices that were established. In addition, in 1996 Duquesne Light Company sold its interest in the Fort Martin Power Station Unit 1 at a price of $169 million, over 4.5 times its book value of $37 million.

Mr. Guth invites me to cite any evidence concerning the willingness of buyers currently to purchase nuclear units at any positive price. He need look no further than Philadelphia. PECO has been very visible in expressing its interest in investing in nuclear assets.

In light of PP&L's stranded cost estimate that places negative value on their generating assets, I suggest that they take Mr. Guth's advice and entertain offers for their generation assets about which he states "PP&L would be very happy to receive and review offers of this magnitude". He does, however, avoid opining that the Company would accept, or that he would recommend that the Company accept "offers of this magnitude." There is very tangible and recent market experience that suggests the Company could find investors that will view their assets as much more valuable than the Company's current estimates.

The unavoidable conclusion is that the electricity market is changing rapidly and the new entities are transforming the notions of ongoing value of the business. The theoretic dicta which Mr. Guth espouses is already being contradicted by the marketplace.

Financial Impacts

Q. DOES THE OCA RECOMMENDATION CAUSE THE DIRE FINANCIAL RESULTS BY MR. SCHADT?

A. No. The example used by Mr. Schadt indicates some restructuring of the CTC charge is likely needed, but the problem is not due to the OCA recommendation of the level of stranded cost recovery. The problem Mr. Schadt addresses is due to the revenue and expense timing difference in the competitive generation function.

There are several major problems with the Company's financial analysis not only of the OCA's proposal, but of its own proposal as well. First, in analyzing the Company's own proposal, Mr. Schadt neglects to reflect the accelerated amortization of the $3.6 billion in stranded costs associated with generating plant that they have estimated. (Schadt, p. 21) This oversight is clearly incorrect. It is a basic accounting standard that expenses be matched as closely as possible with revenues, particularly in a regulatory environment where revenues are <u>set</u> to equal expenses. The Company fails to follow this basic standard. If the Company does not reflect the amortization of above-market generating plant associated with the recovery of stranded costs, the CTC revenues under the Company's proposal would produce after-tax returns on rate base of about 15 percent during the transition period and small or negative returns on rate base after the transition period. If the Company had correctly reflected these amortization expenses, the "Income available for return" under the Company's proposal would be similar to the OCA's, as shown in Exhibit RLC-9.

Which brings us to the real reason why the overall rate of return is, and should be expected to be, as low as these examples show for the year 1999 - the timing of revenues and expenses in the competitive generation market. Unlike traditional revenue requirements, which are designed to be front-loaded, competition will produce a level of market prices that remove this tendency. Exhibit RLC-10 compares the projected revenues available for return for the Susquehanna nuclear plant under a competitive environment to those that would be included in rates under the revenue requirements approach. Furthermore, projected market prices for PJM will be somewhat lower than system long-run marginal costs in the early years of the analysis due to the temporary projection of surplus capacity and energy in the PJM pool. Therefore, PP&L and any other Company choosing to participate in the competitive generation market, should expect returns to be somewhat lower than normal in the early years of the transition period, with profits increasing over time as the pool's capacity and energy become more in balance. The asset valuation approach takes these projected market price factors into account.

If PP&L does not wish to operate under these conditions, it has the option to sell its generation assets. This would leave the Company with T&D assets, which would still earn a regulated rate of return subject to the rate cap provisions of the Act, and the CTC revenues. As such, a "wires" company would not be subject to the same degree of revenue uncertainty as would a generation supplier in the competitive market.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does.

43498

Pennsylvania Power & Light

Summary of PUC Stranded Costs as of January 1, 1999 ($000)

** Includes Revised Market Prices Based on DRI Fall 1996/Winter 1997 Fuel Forecast*

	OCA	Exh. JRS-1	Difference	% Diff.
Net Generating Plant	$3,248,442	N/A	N/A	N/A
Less: Market Value	($3,647,313)	N/A	N/A	N/A
Plus: Fossil Decommissioning	$0	$320,489	($320,489)	***-100.0%***
Stranded Generating Plant	($398,871)	$3,446,523	($3,845,394)	***-111.6%***
Regulatory Assets	$259,249	$383,911	($124,662)	***-32.5%***
NUG Contracts	$563,572	$656,870	($93,298)	***-14.2%***
Nuclear Decommissioning	$108,125	$123,657	($15,532)	***-12.6%***
Total Stranded Cost	**$532,075**	**$4,610,961**	**($4,078,886)**	***-88.5%***

Pennsylvania Power & Light

Summary of PUC Stranded Costs as of January 1, 1999 ($000)

** Includes Revised Market Prices Based on DRI Spring 1997 Fuel Forecast*

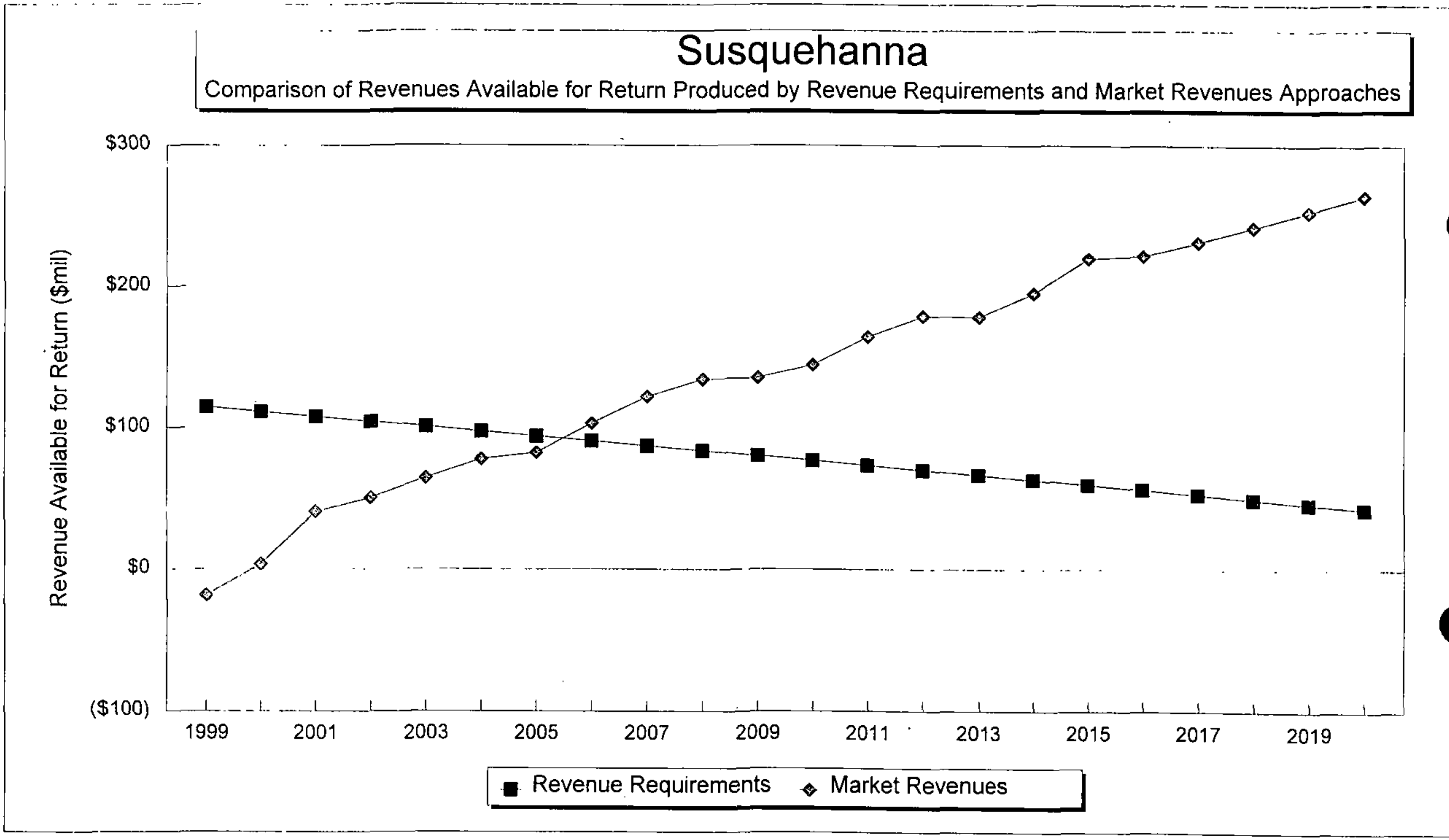
	OCA	*Exh. JRS-1*	*Difference*	*% Diff.*
Net Generating Plant	$3,248,442	N/A	N/A	N/A
Less: Market Value	($3,110,321)	N/A	N/A	N/A
Plus: Fossil Decommissioning	$0	$320,489	($320,489)	***-100.0%***
Stranded Generating Plant	$138,121	$3,446,523	($3,308,402)	***-96.0%***
Regulatory Assets	$259,249	$383,911	($124,662)	***-32.5%***
NUG Contracts	$574,708	$656,870	($82,162)	***-12.5%***
Nuclear Decommissioning	$108,125	$123,657	($15,532)	***-12.6%***
Total Stranded Cost	**$1,080,203**	**$4,610,961**	**($3,530,758)**	***-76.6%***

PP&L Proforma Financial Results

PP&L and OCA Proposals - 1999

	Actual 12 months end 12/31/96	PP&L Adjustments	1999 Proforma	Amortization of Stranded Costs	Corrected 1999 Proforma	OCA Adjustments [1]	OCA 1999 Proforma
Operating Revenues	$2,563,242		$2,563,242		$2,563,242	($410,119)	$2,153,123
Operating Expenses							
Operation & maintenance	$1,362,047	$26,054	$1,388,101		$1,388,101		$1,388,101
Annual depreciation	$316,035	($70,180)	$245,855	$531,279	$777,134	($443,080)	$334,054
Taxes other than income	$189,960		$189,960		$189,960	($18,045)	$171,915
Income taxes	$218,772		$218,772	($220,446)	($1,674)	$21,165	$19,490
Deferred income taxes/ITC	($793)	$64,573	$63,780		$63,780		$63,780
Total Operating Expenses	$2,086,021	$20,447	$2,106,468	$310,833	$2,417,301	($439,961)	$1,977,340
Income Available for Return	**$477,221**	**($20,447)**	**$456,774**	**($310,833)**	**$145,941**	**$29,842**	**$175,783**
Rate Base	$5,064,121		$5,064,121		$5,064,121		$5,064,121
Rate of Return	**9.42%**		**9.02%**		**2.88%**		**3.47%**

[1] Assumes a 16% rate decrease in 1999.


Susquehanna
Comparison of Revenues Available for Return Produced by Revenue Requirements and Market Revenues Approaches
Revenue Available for Return ($mil)
$300
$200
$100
$0
($100)
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
Revenue Requirements
Market Revenues

OCA Statement No. 3

8/27/97
Hurley
w/H

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00973954

DOCUMENT FOLDER

DIRECT TESTIMONY OF

THOMAS S. CATLIN

RECEIVED
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ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

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JULY 1997

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

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COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00973954

Direct Testimony of Thomas S. Catlin

Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science Degree in Water Resources Engineering and Management from Arizona State University (1976). Major areas of study for this degree included pricing policy, economics, and management. I received my Bachelor of Science Degree in Physics and Math from the State University of New York at Stony Brook in 1974. I have also completed graduate courses in financial and management accounting.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From August 1976 until June 1977, I was employed by Arthur Beard Engineers in Phoenix, Arizona, where, among other responsibilities, I conducted economic feasibility, financial and implementation analyses in conjunction with utility construction projects. I also served as project engineer for two utility valuation studies.

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My project administration responsibilities included budget preparation and labor and cost monitoring and forecasting. As a member of CDM's Management Consulting Division, I performed cost of service, rate, and financial studies on approximately 15 municipal and private water, wastewater and storm drainage utilities. These projects included: determining total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; preparing bill analyses; developing cost and revenue projections; and preparing rate filings and expert testimony.

In September 1981, I accepted a position as a utility rates analyst with Exeter Associates, Inc. I became a principal and vice-president of the firm in 1984. Since joining Exeter, I have continued to be involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have been extensively involved in the review and analysis of utility rate filings, as well as other types of proceedings before state and federal regulatory authorities. My work in utility rate filings has focused on revenue requirements issues, but has also addressed service cost and rate design matters. I have also been involved in analyzing affiliate relations, alternative regulatory mechanisms, and regulatory restructuring issues. This experience has involved telephone, natural gas transmission and distribution and water utilities, as well as electric companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony on more than 125 occasions before the Federal Energy Regulatory Commission and the public utility commissions of Arizona, Colorado, Delaware, the District of Columbia, Florida, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Rhode Island, Utah, Virginia and West Virginia, as well as before this Commission. I have also filed rate case evidence by affidavit with the Connecticut Department of Public Utility Control. A copy of my resume with a complete listing of my prior testimony is included as Attachment A to my testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

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

A. I have been retained by the OCA to assist in the review and evaluation of Pennsylvania Power & Light Company's (PP&L's or the Company's) proposed restructuring plan. In particular, I have been asked to address certain components of PP&L's stranded cost claims including nuclear and fossil decommissioning costs and regulatory assets and liabilities including income taxes. The purpose of my testimony is to present my findings and discuss the adjustments which I have determined should be made to PP&L's claims.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Schedules TSC-1 through TSC-5 are attached to my testimony. These schedules present my proposed adjustments to PP&L's stranded cost claims.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. Schedule TSC-2 presents the details of my findings with regard to the regulatory assets to be included in stranded costs. I have presented these findings in the same format utilized by PP&L in Mr. Schadt's Exhibit JRS 1. The total nominal amount of the regulatory assets attributable to Pennsylvania jurisdictional operations which I am proposing to recognize is $595,529,000.[1] As shown on Schedule TSC-3, the net present value of these regulatory assets is $243,201,000 based on the Company's proposed discount rate of 7.92 percent. At the discount rate of 7.24 percent discussed by OCA witness Richard La Capra, the net present value of the regulatory assets which I have identified is $259,249,000, as shown on Schedule TSC-4. In comparison, the nominal balance of regulatory assets claimed by PP&L as allocable to the Pennsylvania jurisdiction is $827,369,000 and the net present value of those regulatory assets based on PP&L's proposed discount rate is $383,911,000. These results are summarized on Schedule TSC-1.

The reduction in the balance of regulatory assets which I am recommending is due to adjustments which I have made to PP&L's claim for unrecovered energy costs, the DOE assessment, Susquehanna deferred refueling costs, employee transition costs, 1994 rate case expenses, and the regulatory liability associated with Investment Tax Credits (ITCs). The difference also reflects a revision to the jurisdictional allocation percentages applicable to certain regulatory assets.

In addition to the adjustments to regulatory assets summarized on Schedule TSC-1, I have also adjusted PP&L's claim for stranded fossil decommissioning costs. It is the OCA's position, as discussed by Mr. La Capra, that these costs should not be considered as an element of stranded costs at all. However, if the costs are to be recognized, the contingencies incorporated in PP&L's projected costs should be eliminated. As shown on Schedule TSC-4, this reduces the nominal fossil decommissioning costs by $97,854,000.

[1]This balance is equal to the sum of the annual amortization amounts for the PUC Jurisdiction shown on Schedule TSC-2.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into sections corresponding to the issues which I will address. These topics are summarized in the table of contents for my testimony.

<u>Unrecovered Energy Costs</u>

Q. PLEASE SUMMARIZE PP&L'S CLAIM WITH REGARD TO UNRECOVERED ENERGY COSTS.

A. PP&L has included $80,150,000 attributable to unrecovered energy costs in its claimed balance of regulatory assets as of January 1, 1999. This balance is comprised of two components. The first component consists of the balance of unrecovered energy costs as of December 31, 1996 in the amount of $17,204,000. The second component consists of energy cost underrecoveries of $62,946,000 projected to be experienced during the years 1997 and 1998.

Q. WHAT IS THE OCA'S RECOMMENDATION WITH REGARD TO THE UNRECOVERED ENERGY COSTS WHICH PP&L HAS CLAIMED AS REGULATORY ASSETS?

A. The OCA does not dispute PP&L's claim for the inclusion of the unrecovered energy costs as of December 31, 1996 as a regulatory asset. However, as explained by OCA witness La Capra, the claimed deferrals for the years 1997 and 1998 should not be included as regulatory assets. Accordingly, I have reduced the Company's claimed balance of regulatory assets as of January 1, 1999 by $62,946,000.

Q. IN ADDITION TO THE REASONS OFFERED BY MR. LA CAPRA AS TO WHY POST-1996 DEFERRED FUEL COSTS SHOULD NOT BE RECOGNIZED AS A

REGULATORY ASSET, DO YOU HAVE ANY ADDITIONAL POINTS YOU WOULD LIKE TO RAISE?

A. Yes. Now that the ECR has been rolled into base rates, the Company's energy costs are being recovered through its existing base rates. It would be inappropriate to allow PP&L to defer energy costs during 1997 and 1998 while the Company remains under traditional regulation without a demonstration that its existing rates are inadequate to recover its energy costs.

Q. WHAT DOES THE INFORMATION PRESENTED IN THE COMPANY'S FILING SHOW WITH REGARD TO THE ADEQUACY OF ITS EXISTING RATES?

A. According to the data presented in Attachment 1 to RP-A.3 of the Commission's filing guidelines, the Company's 1996 per books return on equity was 11.90 percent and its pro forma return on equity is 11.42 percent. Including an additional $31.5 million of energy costs in the cost of service instead of deferring those costs would reduce the Company's return on equity by 80 basis points (.80%). Hence, even if these costs were included in rates, PP&L's pro forma return on equity would remain in excess of 10.6 percent. This is in excess of the 10 percent return on equity which the Commission recently found applicable to PECO Energy Company in its Opinion and Qualified Rate Order in Docket No. R-00973877. However, even if the 11.5 percent return on equity used by PP&L in this proceeding is considered to be the standard of comparison, the Company's pro forma return including the full amount of the claimed energy cost underrecovery is not so low as to warrant the prejudgment that PP&L's rates will be inadequate to recover its total energy costs.

Q. BY CITING PP&L'S PRO FORMA RATE OF RETURN, DO YOU INTEND TO INDICATE YOUR AGREEMENT WITH THE COMPANY'S FINDINGS?

A. No. I believe that the Company has understated its pro forma rate of return. For example, PP&L's analysis does not recognize either consolidated tax savings or the significant reduction in pension expense applicable in 1997 based on 1996 fund results. However, I have not performed a detailed revenue requirement analysis in this proceeding.

DOE Assessment

Q. WHAT HAS PP&L CLAIMED WITH REGARD TO THE DOE ASSESSMENT?

A. Pursuant to the Energy Policy Act of 1992, utilities with nuclear power plants are required to pay an assessment to fund the decommissioning of the U.S. Department of Energy's (DOE's) uranium enrichment facilities. This assessment is in effect for a 15-year period which ends in 2007. PP&L has included the present value of the annual DOE assessments applicable to the years 1999 through 2007 as a regulatory asset.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO PP&L'S CLAIM?

A. In response to PP&L Industrial Customer Alliance Interrogatory Set II, question 10 (PPLICA II-10), PP&L has indicated that projected fuel expenses for the years 1999-2007 include the DOE assessment. Given that this assessment is already recognized as an element of fuel expense, it is not necessary to recognize the DOE assessment as a regulatory asset. Accordingly, I have reduced PP&L's claimed regulatory assets to exclude the present value of the projected annual assessments during 1999-2007. The nominal amount of these assessments is $24,301,000 on a total company basis, of which $22,923,000 is allocable to the Pennsylvania jurisdiction.

Susquehanna Deferred Refueling Outage Costs

Q. PLEASE EXPLAIN PP&L'S CLAIM FOR SUSQUEHANNA DEFERRED REFUELING OUTAGE COSTS.

A. PP&L has included the projected balance of deferred Susquehanna refueling outage costs as of December 31, 1998 as a regulatory asset. This balance consists of the estimated unamortized balance of the projected costs of the 1997 refueling outage at Susquehanna Unit 2 and the 1998 refueling outage at Susquehanna Unit 1. The total projected balance claimed by PP&L is $9,552,000 of which $8,343,000 is Pennsylvania jurisdictional.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE TREATMENT OF SUSQUEHANNA DEFERRED REFUELING OUTAGE COSTS?

A. I am recommending that the projected balance of deferred Susquehanna refueling outage costs not be included as a regulatory asset. Accordingly, I have reduced the total company balance of regulatory assets as of January 1, 1999 by $9,552,000 and the Pennsylvania jurisdictional balance as of that date by $8,343,000.

Q. WHY HAVE YOU PROPOSED TO EXCLUDE THIS BALANCE FROM REGULATORY ASSETS?

A. PP&L established the accounting procedure of deferring and amortizing refueling outage costs in order to normalize the amount of such costs reflected as an expense in any given year. This was necessary because refueling outages have historically occurred at an interval of once every 18 months at each unit or at a rate of four outages every three years for the two units combined. As a result of this accounting procedure, which is also utilized for ratemaking, a normalized level of refueling outage costs is already recognized as an annual expense and is already being recovered in rates. Accordingly, it is unnecessary to also provide recovery of any additional refueling outage costs as a regulatory asset.

In addition, beginning with the 1997 refueling outage at Susquehanna Unit 1 and the 1998 refueling outage at Susquehanna Unit 2, refueling outages will now occur every 24 months at each unit, or at the rate of one outage per year for the two units combined. Therefore, there is no longer any need to defer and amortize refueling outage costs in order to include a normalized level of such costs as an expense. PP&L has indicated that it intends to make this accounting change, but has assumed that the change will take place after 1999.

Employee Transition Costs

Q. PLEASE SUMMARIZE PP&L'S CLAIM WITH REGARD TO THE INCLUSION OF EMPLOYEE TRANSITION COSTS AS A REGULATORY ASSET.

A. PP&L has included as a regulatory asset the employee transition costs which it projects it will incur during the years 1997 to 2001 in conjunction with its efforts to reduce the Company's work force in order to prepare for competition. These costs are comprised of severance payments and incremental pension benefits to be paid to employees accepting early retirement offers. PP&L has assumed that the transition costs incurred in each year would be amortized over the ensuing five years. The Company has then established the amount of its claimed regulatory asset based on the net present value of the amortization allowances in 1999 and subsequent years.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THIS REGULATORY ASSET?

A. I am proposing to make two adjustments to PP&L's claim for employee transition costs. First, I am proposing to eliminate the portion of the Company's claimed regulatory asset related to 1997 and 1998 employee transition costs. Second, I am proposing to adjust the costs per employee to exclude the incremental pension benefits and, instead, include only the cash severance payments to departing employees.

Q. WHY IS IT APPROPRIATE TO EXCLUDE THE PORTION OF THE COMPANY'S CLAIMED REGULATORY ASSET RELATED TO 1997 AND 1998 EMPLOYEE TRANSITION COSTS?

A. The 1997 and 1998 employee transition costs should not be included as a regulatory asset for two reasons. First, the 1996 base period costs presented by PP&L in this case include $7,713,000 for employee transition costs incurred during 1996.[2] In comparison, the projected employee transition costs in 1997 and 1998 are $7.585 million and $10.26 million, respectively. Hence, only a small portion of the 1997 and 1998 transition costs is incremental to the level already recognized as an ongoing cost by PP&L.

Second, the cost savings associated with the projected employee reductions are $71,400 per employee per year compared to the projected one time costs of $97,000 per employee. This means that the employee reductions which take place in 1997 and 1998 will in large part pay for themselves in 1997 and 1998. Assuming the employee reductions projected for each year occur more or less evenly in each year, the cost savings realized by PP&L in 1997 and 1998 will be $12,745,000 compared to costs of $17,845,000. Accordingly, the net costs to P&L in 1997 and 1998 will total only $5.1 million for the two years. This is well less than the $7.7 million annual expense reflected in the base year for employee transition costs, as noted above.

Q. WHY ARE YOU PROPOSING TO EXCLUDE THE INCREMENTAL PENSION BENEFITS FROM THE EMPLOYEE TRANSITION COSTS INCLUDED IN THE DETERMINATION OF THE ASSOCIATED REGULATORY ASSET?

[2]These costs are in addition to the amortization of the voluntary early retirement program costs of $13,132,000 approved in Docket No. R-00943271.

A. The funded percentage of the Company's pension plan is currently 170.8 percent of the accumulated benefit obligation (ABO) and 133.9 percent of the projected benefit obligation (PBO).[3] Because of this overfunding, the incremental pension benefits will not result in any additional out-of-pocket cost to the Company. The effect of the increase in the ABO and PBO attributable to the incremental benefits for all 300 employees which PP&L has projected to participate will be to advance the date at which pension contributions are required by one year, all else being equal. However, there is no requirement for such contributions for at least the next ten years.

Q. WHAT ARE THE EFFECTS OF YOUR ADJUSTMENTS ON THE REGULATORY ASSET ATTRIBUTABLE TO EMPLOYEE TRANSITION COSTS?

A. The effect of my adjustment to exclude employee transition costs projected to be incurred in 1997 and 1998 is to reduce the nominal balance of the regulatory asset associated with employee transition costs allocated to generation by $10,793,000. The effect of my adjustment to recognize only the lump sum severance benefits and exclude the incremental pension benefits further reduces the nominal balance of the regulatory asset by $8,003,000. After reflecting these two adjustments, I am proposing to recognize $3,483,000 associated with employee transition costs as a regulatory asset. The annual amortization amounts for these costs are shown on Schedule TSC-1.

[3] The ABO is present value of the accumulated benefits based on service and pay as of the calculation date and the PBO is the present value of the benefits based on service as of the calculation date and projected pay.

1994 Rate Case Expenses

Q. PLEASE SUMMARIZE PECO'S CLAIM WITH REGARD TO 1994 RATE CASE EXPENSES.

A. In PP&L's 1994 rate case, the Commission determined that the normalized level of rate case expenses should be established based on a four year interval between rate cases. In response to this finding, the Company elected to defer the costs of its rate case on its books and to amortize those costs over four years for accounting purposes. PP&L has included the unamortized balance of these costs which will remain as of December 31, 1998 as a regulatory asset.

Q. DO YOU AGREE THAT THE PER BOOKS BALANCE OF UNAMORTIZED RATE CASE EXPENSES SHOULD BE INCLUDED AS A REGULATORY ASSET?

A. No. For a number of years, it has been the Commission's practice to normalize rate case expenses in determining revenue requirements rather than to approve the deferral and amortization of those costs. If a subsequent case is filed prior to the end of the interval over which rate case expenses were normalized, the Commission has not allowed recovery of amounts related to the prior case. Consistent with this practice, the Commission approved the normalization of rate case expenses for PP&L in Docket No. R-00943271. It did not authorize PP&L to defer and amortize rate case expenses. Accordingly, the Company's claimed balance of unamortized rate case expenses does not qualify as a regulatory asset. Removing these unamortized expenses reduces the nominal balance of regulatory assets by $184,000.

ITC Regulatory Liability

Q. PLEASE EXPLAIN WHAT IS REPRESENTED BY THE ITC REGULATORY LIABILITY.

A. The regulatory liability[4] associated with Investment Tax Credits (ITCs) was recorded in conjunction with PP&L's adoption of Statement of Financial Accounting Standards (SFAS) No. 109. The ITC regulatory liability represents the income tax effect or "gross-up" associated with the balance of accumulated deferred investment tax credits (ADITCs). This balance is equal to the reduction in current income tax expense which will need to be collected from ratepayers as the balance of ADITCs is amortized back to ratepayers over the remaining life of the assets which gave rise to those ITCs.

Q. HOW HAS PP&L TREATED THE ITC REGULATORY LIABILITY IN ITS DETERMINATION OF STRANDED COSTS?

A. PP&L has included the ITC regulatory liability as an offset against the balance of regulatory assets which are included in stranded costs. To accomplish this, PP&L has recognized the amount of the amortization of this liability over the time period the ITCs themselves will be amortized. The present value of the future stream of revenue offsets has then been treated as a deduction from the present value of regulatory assets in determining stranded costs.

Q. WHAT CONCERN DO YOU HAVE WITH PP&L'S CALCULATION OF THE OFFSET TO STRANDED COSTS ASSOCIATED WITH THE ITC REGULATORY LIABILITY?

A. Conceptually, I agree with the procedure which PP&L has followed to recognize the stranded cost offset attributable to the ITC regulatory liability. The one problem which I

[4]The term regulatory liability refers to the fact that this is an amount owed to ratepayers by PP&L as opposed to a regulatory asset which is recoverable from ratepayers.

have identified with regard to PP&L's calculations is that the balance of the ITC regulatory liability which the Company has allocated to its generation assets has been understated. PP&L has recognized $113,591,000 as the ITC regulatory liability associated with its generating assets as of December 31, 1996. The correct balance should be $124,553,000. Therefore, I have adjusted the ITC regulatory liability to reflect this corrected balance as the starting point for determining the offset to stranded costs as of January 1, 1999. The resulting ITC regulatory liability as of January 1, 1999 is $115,656,000 on a total company basis compared to the balance of $105,477,000 recognized by PP&L. On a PUC jurisdictional basis, the annual amortization amounts allocable to Pennsylvania as an offset to stranded costs total $111,052,000[5] compared to a total of $101,278,000 recognized by PP&L.

Q. HOW DID YOU DETERMINE THE CORRECT AMOUNT OF THE ITC REGULATORY LIABILITY ALLOCABLE TO GENERATING ASSETS?

A. To calculate the correct balance of ITC regulatory asset allocable to generating assets, I multiplied the total ITC regulatory asset per books as of December 31, 1996 by the ratio of generation related ITCs to total ITCs as of that date. I also verified this to be the correct amount by grossing up the generation related ITCs directly. In each case, the correct balance was calculated to be $124,553,000.

[5]This figure is prior to the revision to jurisdictional allocation percentages discussed subsequently.

Jurisdictional Allocation Percentages

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE JURISDICTIONAL ALLOCATION PERCENTAGES APPLICABLE TO CERTAIN REGULATORY ASSETS?

A. In its filing, PP&L has assumed that the percentage of certain generation related regulatory assets allocable to the Pennsylvania jurisdiction will increase over time as existing bulk power sales agreements expire. On behalf of the OCA, Mr. La Capra is recommending that the jurisdictional allocation percentage found applicable to PP&L's nuclear and fossil plants in PP&L's rate case in Docket No. R-00943271 continue to be utilized in the determination of Pennsylvania jurisdictional stranded costs. I have adjusted the percentages of those regulatory assets which are subject to jurisdictional allocation to reflect Mr. La Capra's recommendation. This affects the balance of taxes recoverable and the offset to regulatory assets attributable to the ITC regulatory liability. The change would also affect the balances of the DOE assessment and Susquehanna deferred refueling costs allocable to the Pennsylvania jurisdiction. However, as discussed previously, I am proposing to exclude those balances from regulatory assets in their entirety.

Q. WHAT IS THE EFFECT OF THE CHANGE IN ALLOCATION FACTORS ON THE BALANCES OF TAXES RECOVERABLE AND THE ITC REGULATORY LIABILITY ALLOCABLE TO THE PENNSYLVANIA JURISDICTION?

A. The changes to the jurisdictional allocation percentages for nuclear and fossil generating assets reduce the balance of taxes recoverable allocable to Pennsylvania from the $727,444,000 claimed by PP&L to $599,081,000. Similarly, the changes in allocation factors reduce the jurisdictional balance of the ITC regulatory liability available to offset stranded costs from the adjusted balance of $111,052,000 which I previously calculated to $91,563,000.

Fossil Decommissioning Costs

Q. PLEASE EXPLAIN HOW PP&L HAS TREATED FOSSIL DECOMMISSIONING COSTS IN DEVELOPING ITS STRANDED COST CLAIM.

A. PP&L has included fossil decommissioning costs in its calculation of the future costs associated with its various fossil fueled generating units. To accomplish this, the Company escalated the current decommissioning costs for each fossil plant to the projected price levels at the time those costs are expected to be incurred. The costs for each unit were assumed to be incurred 40 percent in the year of retirement and then 40 percent and 20 percent in the two succeeding years. These costs were then discounted back to a net present value as of January 1, 1999 to obtain the stranded cost to be recovered from ratepayers.

Q. DO YOU AGREE WITH PP&L'S CLAIM FOR FOSSIL DECOMMISSIONING COSTS?

A. No. As explained in detail by OCA witness La Capra, fossil decommissioning costs should not be included in the determination of stranded costs. However, if the Commission does decide that it is appropriate to recognize fossil decommissioning costs, the amount of the Company's claim should be adjusted.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO PP&L'S CLAIM FOR STRANDED COSTS ASSOCIATED WITH FOSSIL DECOMMISSIONING?

A. PP&L's decommissioning cost estimates for the Holtwood, Sunbury, Martin's Creek, Brunner Island, and Montour generating stations which it owns include contingency factors in the range of 16.5 to 18.7 percent. In addition, the decommissioning cost estimates provided by the operator of the Keystone and Conemaugh units of which PP&L is a part owner include contingency factors of 15 percent. I am proposing to adjust the decommissioning costs included in the determination of stranded costs to exclude these contingencies. This is consistent with the Commission's decision in PP&L's last rate case at Docket No. R-00943271 in which the Commission eliminated the contingencies built into the Company's nuclear decommissioning cost estimates. As the Commission noted in that decision, there is no reason to conclude "... that speculative future costs necessitate a large contingency factor which rests, in itself, on total estimated costs which are far from certain." (p. 82)

Q. HAVE YOU PREPARED A SCHEDULE WHICH SUMMARIZES THE EFFECT OF REMOVING THE CONTINGENCIES FROM PP&L'S DECOMMISSIONING COST ESTIMATES?

A. Yes, Schedule TSC-5 shows the decommissioning costs for each generating station as claimed by PP&L, the amount of the contingencies included in those estimates and the amount of decommissioning costs excluding contingencies. As indicated there, excluding contingencies reduces the fossil decommissioning costs by $97,854,000 in nominal dollars.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

OCA Statement No. 3

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00973954

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 1997

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

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Regulatory Assets
as of December 31, 1998
($000)

	Amount Per Company (1)	Amount Per OCA (2)
Unrecovered Energy Costs	$80,150	$17,204
Post Retirement Benefits	14,496	14,496
Recoverable SSES Operating Costs	12,836	12,836
Common Plant Adjustment	18,220	18,220
Retired Miners' Health Care Costs	6,582	6,582
DOE Assessment	22,923	0
SSES Deferred Refueling Costs	8,343	0
Voluntary Early Retirement Costs	15,190	15,190
Employee Transition Costs	22,279	3,483
1994 Rate Case Expenses	184	0
Recoverable Taxes	727,444	599,081
Regulatory Liabilities (Invest Tax Credits)	(101,278)	(91,563)
Total Regulatory Assests-Nominal	$827,369	$595,529
Net Present Value at 7.92%	$383,911	$243,201
Net Present Value at 7.24%		$259,249

Notes:
(1) Per Exhibit JRS 1.
(2) Per Schedules TSC-2 through TSC-4.

REGULATORY ASSETS

	ACCT	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
					THOUSANDS OF DOLLARS						
UNRECOVERED ENERGY COSTS											
BEGINNING OF YEAR	18230		16,889	17,204	17,204						
ADDITIONS			315	0							
AMORTIZATION			0	0	(17,204)						
END OF YEAR		16,889	17,204	17,204	0						
POST RETIREMENT BENEFITS											
BEGINNING OF YEAR	18232		16,559	15,528	14,496	13,464	12,432	11,400	10,368	9,337	8,305
ADDITIONS											
AMORTIZATION			(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)
END OF YEAR -- PUC		25,052	15,528	14,496	13,464	12,432	11,400	10,368	9,337	8,305	7,273
GEN ALLOCATION 66.1%		16,559									
RECOVERABLE SUSQ OPER COSTS NET											
BEGINNING OF YEAR	18233		16,504	14,670	12,836	11,002	9,168	7,334	5,500	3,666	1,832
ADDITIONS	25404		0	0	0	0	0	0	0	0	0
AMORTIZATION	19055		(1,834)	(1,834)	(1,834)	(1,834)	(1,834)	(1,834)	(1,834)	(1,834)	(1,832)
END OF YEAR		16,504	14,670	12,836	11,002	9,168	7,334	5,500	3,666	1,832	0
COMMON PLANT ADJ											
BEGINNING OF YEAR	18234		20,764	19,492	18,220	17,505	16,789	16,074	15,359	14,643	13,928
ADDITIONS			0	0	0	0	0	0	0	0	0
AMORTIZATION SUSQ			(1,245)	(1,245)	(688)	(688)	(688)	(688)	(688)	(688)	(688)
AMORTIZATION MC			(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)
END OF YEAR		20,764	19,492	18,220	17,505	16,789	16,074	15,359	14,643	13,928	13,213
RETIRED MINERS' HEALTH CARE COSTS	Note : This asset is already present valued										
BEGINNING OF YEAR	18235		9,135	7,014	6,582						
ADDITIONS			(564)	1,125	0						
AMORTIZATION			(1,557)	(1,557)	(6,582)						
END OF YEAR		9,135	7,014	6,582	0						
DOE ASSESSMENT											
BEGINNING OF YEAR	18236		0	0	0	0	0	0	0	0	0
ADDITIONS											
TOTAL AMORTIZATION			0	0	0	0	0	0	0	0	0
PUC AMORTIZATION			0	0	0	0	0	0	0	0	0
END OF YEAR		0	0	0	0	0	0	0	0	0	0
SSES DEFERRED REFUELING COSTS											
BEGINNING OF YEAR	18237		0	0	0						
ADDITIONS			0	0							
TOTAL AMORTIZATION			0	0	0						
PUC AMORTIZATION			0	0	0						
END OF YEAR		0	0	0	0						

SCHEDULE TSC-2

	ACCT	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
VOLUNTARY EARLY RETIREMENT COSTS											
BEGINNING OF YEAR	18238		32,551	23,871	15,190	6,510					
ADDITIONS			0	0	0	0					
AMORTIZATION			(8,680)	(8,680)	(8,680)	(6,510)					
END OF YEAR		49,245	23,871	15,190	6,510	0					
GEN ALLOCATION 66.1%		32,551									
EMPLOYEE TRANSITION COSTS											
BEGINNING OF YEAR			0	0	0	1,260	1,953	2,790	2,093	1,397	700
ADDITIONS			0	0	1,260	945	1,278				
AMORTIZATION				0	0	(252)	(441)	(697)	(697)	(697)	(445)
END OF YEAR		0	0	0	1,260	1,953	2,790	2,093	1,397	700	256
GEN ALLOCATION 66.1%											
1994 RATE CASE EXPENSES											
BEGINNING OF YEAR	18239		0	0	0						
ADDITIONS			0	0	0						
AMORTIZATION			0	0	0						
END OF YEAR		0	0	0	0						
GEN ALLOCATION 66.1%		0									
TAXES RECOVERABLE											
BEGINNING OF YEAR	18231		813,070	786,214	755,805	740,706	725,066	709,668	696,571	682,350	667,039
ADDITIONS			0	0	0						
TOTAL AMORTIZATION			(26,856)	(30,409)	(15,099)	(15,640)	(15,398)	(13,097)	(14,221)	(15,311)	(16,796)
AMORTIZATION PUC JURISDICATION - Nuclear			(16,540)	(18,728)	(9,299)	(9,632)	(9,483)	(8,066)	(8,758)	(9,430)	(10,344)
AMORTIZATION PUC JURISDICTION-Other Prod			(4,747)	(5,375)	(2,669)	(2,765)	(2,722)	(2,315)	(2,514)	(2,706)	(2,969)
END OF YEAR- GENERATION		813,070	786,214	755,805	740,706	725,066	709,668	696,571	682,350	667,039	650,243
REG LIABILITIES (INVEST TAX CREDIT)											
BEGINNING OF YEAR	25405		(124,553)	(120,105)	(115,656)	(111,208)	(106,760)	(102,311)	(97,863)	(93,415)	(88,966)
ADDITIONS											
AMORTIZATION			4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448
AMORTIZATION PUC JURISDICATION - Nuclear			2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523
AMORTIZATION PUC JURISDICTION-Other Prod			998	998	998	998	998	998	998	998	998
END OF YEAR- GENERATION		(124,553)	(120,105)	(115,656)	(111,208)	(106,760)	(102,311)	(97,863)	(93,415)	(88,966)	(84,518)
TOTAL BEGINNING OF YEAR BALANCE			800,919	763,888	724,677	679,239	658,649	644,955	632,029	617,978	602,838
ADDITIONS			(249)	1,125	1,260	945	1,278	0	0	0	0
AMORTIZATION-PUC JURISDICTION			**(32,141)**	**(34,957)**	**(44,494)**	**(19,218)**	**(12,706)**	**(11,137)**	**(12,028)**	**(12,892)**	**(13,815)**
AMORTIZATION-TOTAL			(36,756)	(40,309)	(46,671)	(21,508)	(14,945)	(12,899)	(14,023)	(15,113)	(16,344)
TOTAL END OF YEAR BALANCE		800,919	763,915	724,704	679,266	658,676	644,982	632,056	618,005	602,865	586,493

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Reg Assets

REGULATORY ASSETS	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
					THOUSANDS OF DOLLARS						
UNRECOVERED ENERGY COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
POST RETIREMENT BENEFITS											
BEGINNING OF YEAR	7,273	6,241	5,209	4,178	3,146	2,114	1,082	50			
ADDITIONS											
AMORTIZATION	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(1,032)	(50)			
END OF YEAR -- PUC	6,241	5,209	4,178	3,146	2,114	1,082	50	0			
GEN ALLOCATION 66.1%											
RECOVERABLE SUSQ OPER COSTS NET											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
COMMON PLANT ADJ											
BEGINNING OF YEAR	13,213	12,498	11,782	11,067	10,352	9,636	8,948	8,260	7,571	6,883	6,195
ADDITIONS	0	0	0	0	0	0	0	0			
AMORTIZATION SUSQ	(688)	(688)	(688)	(688)	(688)	(688)	(688)	(688)	(688)	(688)	(688)
AMORTIZATION MC	(27)	(27)	(27)	(27)	(27)						
END OF YEAR	12,498	11,782	11,067	10,352	9,636	8,948	8,260	7,571	6,883	6,195	5,506
RETIRED MINERS' HEALTH CARE COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
DOE ASSESSMENT											
BEGINNING OF YEAR	0	0									
ADDITIONS											
TOTAL AMORTIZATION	0	0									
PUC AMORTIZATION	0	0									
END OF YEAR	0	0									
SSES DEFERRED REFUELING COSTS											
BEGINNING OF YEAR											
ADDITIONS											
TOTAL AMORTIZATION											
PUC AMORTIZATION											
END OF YEAR											

SCHEDULE TSC-2

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
VOLUNTARY EARLY RETIREMENT COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
GEN ALLOCATION 66.1%											
EMPLOYEE TRANSITION COSTS											
BEGINNING OF YEAR	256										
ADDITIONS											
AMORTIZATION	(256)										
END OF YEAR	0										
GEN ALLOCATION 66.1%											
1994 RATE CASE EXPENSES											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
GEN ALLOCATION 66.1%											
TAXES RECOVERABLE											
BEGINNING OF YEAR	650,243	631,169	608,999	583,570	547,968	488,450	455,167	418,324	377,506	323,080	270,042
ADDITIONS											
TOTAL AMORTIZATION	(19,074)	(22,170)	(25,429)	(35,602)	(59,518)	(33,283)	(36,843)	(40,818)	(54,426)	(53,038)	(34,022)
AMORTIZATION PUC JURISDICATION - Nuclear	(11,747)	(13,654)	(15,661)	(21,927)	(36,656)	(20,498)	(22,691)	(25,139)	(33,520)	(32,665)	(20,953)
AMORTIZATION PUC JURISDICTION-Other Prod	(3,372)	(3,919)	(4,495)	(6,293)	(10,520)	(5,883)	(6,512)	(7,215)	(9,620)	(9,375)	(6,014)
END OF YEAR- GENERATION	631,169	608,999	583,570	547,968	488,450	455,167	418,324	377,506	323,080	270,042	236,020
REG LIABILITIES (INVEST TAX CREDIT)											
BEGINNING OF YEAR	(84,518)	(80,070)	(75,621)	(71,173)	(66,725)	(62,276)	(57,828)	(53,380)	(48,932)	(44,483)	(40,035)
ADDITIONS											
AMORTIZATION	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448
AMORTIZATION PUC JURISDICATION - Nuclear	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523
AMORTIZATION PUC JURISDICTION-Other Prod	998	998	998	998	998	998	998	998	998	998	998
END OF YEAR- GENERATION	(80,070)	(75,621)	(71,173)	(66,725)	(62,276)	(57,828)	(53,380)	(48,932)	(44,483)	(40,035)	(35,587)
TOTAL BEGINNING OF YEAR BALANCE	586,466	569,838	550,369	527,641	494,740	437,924	407,369	373,254	336,146	285,480	236,202
ADDITIONS	0	0	0	0	0	0	0	0	0	0	0
AMORTIZATION-PUC JURISDICTION	**(13,600)**	**(15,798)**	**(18,382)**	**(26,445)**	**(45,402)**	**(24,580)**	**(27,402)**	**(29,571)**	**(40,307)**	**(39,207)**	**(24,134)**
AMORTIZATION-TOTAL	(16,601)	(19,442)	(22,701)	(32,874)	(56,790)	(30,555)	(34,115)	(37,108)	(50,666)	(49,278)	(30,262)
TOTAL END OF YEAR BALANCE	569,865	550,396	527,668	494,767	437,951	407,369	373,254	336,146	285,480	236,202	205,940

REGULATORY ASSETS

	THOUSANDS OF DOLLARS										
	2017	2018	2019	2020	2021	2022	2023	2024			
UNRECOVERED ENERGY COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
POST RETIREMENT BENEFITS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR -- PUC											
GEN ALLOCATION 86.1%											
RECOVERABLE SUSQ OPER COSTS NET											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
COMMON PLANT ADJ											
BEGINNING OF YEAR	5,506	4,818	4,130	3,442	2,753	2,065	1,377	688			
ADDITIONS											
AMORTIZATION SUSQ	(688)	(688)	(688)	(688)	(688)	(688)	(688)	(688)			
AMORTIZATION MC											
END OF YEAR	4,818	4,130	3,442	2,753	2,065	1,377	688	0			
RETIRED MINERS' HEALTH CARE COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
DOE ASSESSMENT											
BEGINNING OF YEAR											
ADDITIONS											
TOTAL AMORTIZATION											
PUC AMORTIZATION											
END OF YEAR											
SSES DEFERRED REFUELING COSTS											
BEGINNING OF YEAR											
ADDITIONS											
TOTAL AMORTIZATION											
PUC AMORTIZATION											
END OF YEAR											

	2017	2018	2019	2020	2021	2022	2023	2024			
VOLUNTARY EARLY RETIREMENT COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
GEN ALLOCATION 66.1%											
EMPLOYEE TRANSITION COSTS											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
GEN ALLOCATION 66.1%											
1994 RATE CASE EXPENSES											
BEGINNING OF YEAR											
ADDITIONS											
AMORTIZATION											
END OF YEAR											
GEN ALLOCATION 66.1%											
TAXES RECOVERABLE											
BEGINNING OF YEAR	236,020	191,723	159,876	134,385	120,125	115,129	62,361	59,739			
ADDITIONS											
TOTAL AMORTIZATION	(44,297)	(31,847)	(25,491)	(14,260)	(4,996)	(52,768)	(2,622)	(59,739)			
AMORTIZATION PUC JURISDICATION - Nuclear	(27,282)	(19,614)	(15,699)	(8,782)	(3,077)	(32,499)	(1,615)	(36,792)			
AMORTIZATION PUC JURISDICTION-Other Prod	(7,830)	(5,629)	(4,506)	(2,521)	(883)	(9,327)	(463)	(10,559)			
END OF YEAR- GENERATION	191,723	159,876	134,385	120,125	115,129	62,361	59,739	0			
REG LIABILITIES (INVEST TAX CREDIT)											
BEGINNING OF YEAR	(35,587)	(31,138)	(26,690)	(22,242)	(17,793)	(13,345)	(8,897)	(4,448)			
ADDITIONS											
AMORTIZATION	4,448	4,448	4,448	4,448	4,448	4,448	4,448	4,448			
AMORTIZATION PUC JURISDICATION - Nuclear	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523			
AMORTIZATION PUC JURISDICTION-Other Prod	998	998	998	998	998	998	998	998			
END OF YEAR- GENERATION	(31,138)	(26,690)	(22,242)	(17,793)	(13,345)	(8,897)	(4,448)	0			
TOTAL BEGINNING OF YEAR BALANCE	205,940	165,403	137,316	115,585	105,085	103,849	54,841	55,979			
ADDITIONS	0	0	0	0	0	0	0	0			
AMORTIZATION-PUC JURISDICTION	**(32,278)**	**(22,410)**	**(17,372)**	**(8,470)**	**(1,127)**	**(38,993)**	**755**	**(44,518)**			
AMORTIZATION-TOTAL	(40,537)	(28,087)	(21,731)	(10,500)	(1,236)	(49,008)	1,138	(55,979)			
TOTAL END OF YEAR BALANCE	165,403	137,316	115,585	105,085	103,849	54,841	55,979	0			

SCHEDULE TSC-3

Net Present Value
of Regulatory Assets at
7.92% Discount Rate

(thousands of $)											
REGULATORY ASSETS	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Amortization	(32,141)	(34,957)	(44,494)	(19,218)	(12,706)	(11,137)	(12,028)	(12,892)	(13,815)	(13,600)	(15,798)
Total NPV - Reg. Assets	(269,444)	(258,243)	(243,201)	(217,032)	(214,928)	(219,404)	(225,876)	(231,954)	(237,636)	(242,827)	(248,668)

SCHEDULE TSC-3

Net Present Value
of Regulatory Assets at
7.92% Discount Rate

(thousands of $)											
REGULATORY ASSETS	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Amortization	(18,382)	(26,445)	(45,402)	(24,580)	(27,402)	(29,571)	(40,307)	(39,207)	(24,134)	(32,278)	(22,410)
Total NPV - Reg. Assets	(252,709)	(254,403)	(247,873)	(221,146)	(213,819)	(202,963)	(188,967)	(162,686)	(135,387)	(121,478)	(97,980)

SCHEDULE TSC-3

Net Present Value
of Regulatory Assets at
7.92% Discount Rate

(thousands of $)							
REGULATORY ASSETS	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Amortization	(17,372)	(8,470)	(1,127)	(38,993)	755	(44,518)	-
Total NPV - Reg. Assets	(82,786)	(71,570)	(68,664)	(73,136)	(38,704)	(42,666)	-

SCHEDULE TSC-4

Net Present Value
of Regulatory Assets at
7.24% Discount Rate

(thousands of $)											
REGULATORY ASSETS	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Amortization	(32,141)	(34,957)	(44,494)	(19,218)	(12,706)	(11,137)	(12,028)	(12,892)	(13,815)	(13,600)	(15,798)
Total NPV - Reg. Assets	(286,595)	(274,819)	(259,249)	(232,654)	(230,199)	(234,294)	(240,317)	(245,870)	(250,945)	(255,445)	(260,505)

SCHEDULE TSC-4

Net Present Value
of Regulatory Assets at
7.24% Discount Rate

(thousands of $)											
REGULATORY ASSETS	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Amortization	(18,382)	(26,445)	(45,402)	(24,580)	(27,402)	(29,571)	(40,307)	(39,207)	(24,134)	(32,278)	(22,410)
Total NPV - Reg. Assets	(263,671)	(264,403)	(256,854)	(229,141)	(220,880)	(209,084)	(194,162)	(167,024)	(138,991)	(124,444)	(100,388)

SCHEDULE TSC-4

Net Present Value
of Regulatory Assets at
7.24% Discount Rate

(thousands of $)							
REGULATORY ASSETS	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Amortization	(17,372)	(8,470)	(1,127)	(38,993)	755	(44,518)	-
Total NPV - Reg. Assets	(84,733)	(73,116)	(69,832)	(73,894)	(39,112)	(42,820)	-

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Fossil Decommissioning Costs
to Exclude Contingency Allowances
($000)

	Total Cost (1)	Contingency	Net Allowable
Holtwood Units 15, 16 & 17	$43,614	$6,183	$37,431
Sunbury Units 1-4	136,412	20,455	115,957
Martins Creek Units 1 & 2	71,867	11,079	60,788
Martins Creek Units 3 & 4	74,666	11,158	63,508
Brunner Island Units 1-3	168,082	26,494	141,588
Montour Units 1 & 2	133,889	20,559	113,330
Conemaugh (2)	7,282	950	6,332
Keystone (2)	7,486	976	6,510
Total	$643,298	$97,854	$545,444

Notes:

(1) Reflect cost estimates in 1994 dollars except where noted.

(2) Amounts reflect PP&L's share of estimated costs in 1996 dollars.

ATTACHMENT

TO

DIRECT TESTIMONY OF
THOMAS S. CATLIN

THOMAS S. CATLIN

Mr. Catlin is a principal in Exeter Associates, Inc. He is a senior utility rate analyst with a combination management and analytical background. His areas of specialization are revenue requirements and cost of service.

Mr. Catlin has extensive experience in the review and analysis of the operations of public utilities. The emphasis of this work has been on utility rate regulation and has involved telephone, natural gas, electric and water companies. He is familiar with all aspects of utility ratemaking, the use of economic and engineering analytical techniques, rate base and operating income determination, income taxes, and utility accounting. Mr. Catlin has provided expert testimony before the Arizona, California, Colorado, Delaware, District of Columbia, Florida, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Utah, Virginia and West Virginia public utility commissions as well as before the Federal Energy Regulatory Commission. This testimony has addressed all aspects of utility regulation including revenue requirements, cost of service, and rate design. Mr. Catlin has also been responsible for conducting cost of service, rate, and financial studies involving municipal and investor-owned water, wastewater, and storm drainage utilities.

Education:

B.S. (Physics with minor in Math) - State University of New York at Stony Brook, 1974.

M.S. (Water Resources Engineering & Management) - Arizona State University, 1976.

Graduate courses in Accounting - Suffolk University, 1978-79.

Previous Employment:

1978-1981	Utility Rates Specialist, Camp Dresser & McKee, Inc.
1977-1978	Engineer, Camp Dresser & McKee, Inc.
1976-1977	Engineer, Arthur Beard Engineers, Inc.

Professional Work:

Mr. Catlin has participated in rate cases for telephone, natural gas, electric and water utilities. This work has included the review, analysis and presentation of expert testimony regarding all aspects of revenue requirements including rate base, revenues, expenses, and income taxes. This work has also involved conducting and testifying on marginal and embedded cost studies and rate design. In the natural gas area, Mr. Catlin has been involved in conducting management audits and similar reviews of the gas supply and procurement policies and practices of natural gas distribution companies. His work in this area has also addressed minimum bill issues and take or pay cost recovery, as well as the review of PGA filings at both the state and federal level. In the telecommunications area, Mr. Catlin has conducted and testified with regard to cost of service and rate design studies and analyses for a variety of both monopoly and competitive services. This has included the issue of carrier and subscriber access charges. In addition to providing testimony and assisting in the litigation of rate cases, Mr. Catlin has also been involved in negotiating settlements of a number of cases.

At Camp Dresser & McKee, Inc., Mr. Catlin was a project manager for utility rates, financial, and economic studies. He performed studies on approximately 15 municipal and private water, wastewater and storm drainage utilities. His assignments involved: determining the total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; bill analyses; cost and revenue projections; preparing rate filings; and expert testimony.

Prior to transferring to the Camp Dresser & McKee's management service group, Mr. Catlin was an environmental engineer with CDM. He was involved in both project administration and design. Project administration and control responsibilities included budget preparation, labor and cost monitoring and forecasting, and contract preparation.

At Arthur Beard Engineers, Inc., Mr. Catlin served as project coordinator for a major environmental impact statement. He also served as project engineer for a county-wide water supply study and two utility valuation studies.

Publications:

"Effects of Pricing Policy on Residential Water Use," Masters Degree research paper, Arizona State University, 1976.

"Water Rate Policy," presented to Water Resources Policy Committee of California Section of AWWA, 1977.

"Try Capacity Charges to Generate Water Utility Capital," American City and County, February 1981.

"Rate Structure Alternative for Utilities," with John J. Gall, Public Works Magazine, June 1982.

"A First Look at the Effect of the Tax Reform Act of 1986 on Public Utility Ratemaking," with Matthew I. Kahal, October 1986.

"State Implementation of the Tax Reform Act Changes," presented to the National Association of State Utility Consumer Advocates, November 1986.

"Three Ratemaking Issues Arising from The Tax Reform Act of 1986," presented to the National Association of State Utility Consumer Advocates, November 1987.

"SFAS No. 106 and Public Utility Ratemaking," with Randy M. Allen, May 1991.

Prior Expert Testimony

of Thomas S. Catlin

Before State Commissions:

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket 1513), February 1981. Testified on revenue requirements, cost of service and rate design on behalf of the Providence Water Supply Board.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket RID 1819), April & May 1982. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Washington Gas Light Company (Maryland Public Service Commission, Case No. 7649), October 1982. Testified on cost of service issues on behalf of the Maryland People's Counsel.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832316), August 1983. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 798), October 1983. Testified on cost of service on behalf of the Public Service Commission Staff.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832493), April 1984. Testified on revenue, expense, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation Concerning Intrastate Access Charges (Pennsylvania Public Utility Commission, Docket P-830452), August 1984. Testified on telephone access service costs and subscriber access charge issues on behalf of the Pennsylvania Office of Consumer Advocate.

Gulf Power Company (Florida Public Service Commission, Docket 840086-EI), August 1984. Testified on rate base issues on behalf of the Federal Executive Agencies.

Western Pennsylvania Water Company (Pennsylvania Public Utility Commission, Docket R-842621, et al.), August 1984. Testified on revenue, expense, rate base, and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

ALLTEL Pennsylvania (Pennsylvania Public Utility Commission, Docket R-842710), January 1985. Testified on revenue, expense, rate base and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 827), March 1985. Testified on cost of service matters on behalf of the Office of People's Counsel.

Chesapeake & Potomac Telephone Company (Maryland Public Service Commission, Case No. 7851), March 1985. Testified on cost of service matters on behalf of the Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-842632), March 1985. Testified on rate base, expense and income tax issues on behalf of the Office of Consumer Advocate.

New England Telephone and Telegraph Company (Rhode Island Public Utilities Commission, Consolidated Docket 1560(R), 1631, 1654), April 1985. Testified on category cost of service and service cost matters on behalf of the Division of Public Utilities and Carriers.

Chesapeake & Potomac Telephone Company (West Virginia Public Service Commission, Case No. 84-747-T-42T), June 1985. Testified on rate base and expense issues, impacts of divestiture, and separations issues on behalf of the Public Service Commission, Consumer Advocate Division.

Oklahoma Gas & Electric Company (Oklahoma Corporation Commission, Cause No. 29450), July 1985. Testified on rate base, operating income and income tax issues on behalf of the Attorney General.

Bristol County Water Company (Rhode Island Public Utilities Commission, Docket No. 1811), August 1985. Testified on rate base, operating income and income tax issues on behalf of the Division of Public Utilities and Carriers.

Continental Telephone Company of Pennsylvania and Quaker State Telephone Company (Pennsylvania Public Utility Commission, Docket Nos. R-850044 and R-850045, Consolidated hearings), September 1985. Testified on rate base, toll revenue, expense and income tax matters on behalf of the Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-850174), November 1985. Testified on rate base, revenue, expense and income tax issues on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220), January 1986. Testified on rate base and net operating income issues on behalf of the Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-860296), March 1986. Testified regarding purchased gas costs and cost recovery on behalf of the Office of Consumer Advocate.

Idaho Power Company (Idaho Public Utilities Commission, Case No. U-1006-265), April 1986. Testified on rate base, operating expense, and income tax matters on behalf of the Federal Executive Agencies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-850287), July 1986. Testified regarding rate base, revenue, expense, and income tax issues on behalf of the Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350), July 7, 1986. Testified in rate base, operating revenue and expense, and income tax issues on behalf of the Office of Consumer Advocate.

Blackstone Valley Electric Company (Rhode Island Public Utilities Commission, Docket No. 1849), August 1986. Testified on rate base, revenue, expense and income tax issues on behalf of the Division of Public Utilities and Carriers.

Dayton Power and Light Company (Public Utilities Commission of Ohio, Case No. 86-17-GA-GCR), August 1986. Testified regarding audit of management and performance of gas purchasing policies and practices on behalf of the Public Utilities Commission of Ohio.

West Virginia Water Company (West Virginia Public Service Commission, Case No. 86-212-W-42T), October 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Kentucky West Virginia Gas Company (Federal Energy Regulatory Commission, Docket No. RP86-52-000), November 1986. Testified on elimination of the minimum bill and take or pay exposure on behalf of the Pennsylvania Office of Consumer Advocate.

Huntington Water Corporation (West Virginia Public Service Commission, Case No. 86-341-W-42T), December 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. 16945), December 1986. Testified on rate base, revenue, expense, income tax and phase-in issues on behalf of the Staff of the Commission.

Mountain States Telephone and Telegraph Company (Colorado Public Utilities Commission, Docket No. 1720), December 1986. Testified on the measurement of dial tone or access line costs and separations procedures on behalf of the Colorado Office of Consumer Counsel.

Columbia Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP86-168-000), April 1987. Testified on rate base, operating income, and income taxes on behalf of the Commonwealth of Pennsylvania Office of Consumer Advocate.

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP87-7-000), May 1987. Testified on appropriate regulatory treatment of surplus proceeds resulting from termination of pension plan on behalf of the Pennsylvania Office of Consumer Advocate.

Monongahela Power Company (West Virginia Public Service Commission, Case No. 86-524-E-SC), May 1987. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division.

Atlantic City Sewerage Company (New Jersey Board of Public Utilities, Docket No. WO 8606654), June and August 1987. Presented testimony on behalf of Resorts International, Inc., addressing responsibility of Company to pay cost of extending facilities.

Newport Electric Corporation (Rhode Island Public Utilities Commission, Docket No. 1872), July 1987. Testified on rate base and operating income issues, including the effects of the Tax Reform Act of 1986 on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

General Telephone of the South (West Virginia Public Service Commission, Case No. 86-870-T-42T), July 1987. Testified on rate base, operating income and jurisdictional separations issues on behalf of the Consumer Advocate Division of the Public Service Commission. (Case settled prior to cross-examination.)

Philadelphia Electric Company-Gas Operations (Pennsylvania Public Utility Commission, Docket No. R-870629), August 1987. Testified on operating income and income tax matters on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220 Reconsideration), August 1987. Testified on issue of retroactive ratemaking and revenue requirement effects of alternative excess capacity adjustments recommended by others on behalf of Pennsylvania Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350 Reconsideration), September 1987. Testified on recognition of proper balance of deferred income taxes collected from ratepayers on behalf of Pennsylvania Office of Consumer Advocate.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio Case No. 87-29-GA-GCR), October 1987. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket No. M-860105, F. 18), November 1987. Testified on effects of Tax Reform Act of 1986 on behalf of Pennsylvania Office of Consumer Advocate.

Panhandle Eastern Pipe Line Company (Federal Energy Regulatory Commission, Docket No. RP87-103-000), February 1988. Testified on rate base, operating income and income tax issues on behalf of Indiana Office of Utility Consumer Counselor.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-870840), February 1988. Testified on revenue, expense, income tax, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Sierra Pacific Power Company-Water Department (Nevada Public Service Commission, Docket No. 87-1226), April 1988. Testified on cost of service allocation on behalf of the Nevada Office of Consumer Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA86-19-001), April 1988. Testified regarding cost of service tariff (formula rate) issues on behalf of the Louisiana Public Service Commission.

The Peoples Natural Gas Company (Pennsylvania Public Utilities Commission Docket No. R-880961), August 1988. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission Docket No. U-17906), September 1988. Testified on operating income and rate making policy issues on behalf of the Staff of the Commission.

National Gas and Oil Corporation (Public Utilities Commission of Ohio Case No. 88-22-GA-GCR), September 1988. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 88-24-GA-GCR), October 1988. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Providence Gas Company (Rhode Island Public Utilities Commission Docket No. 1914), December 1988. Testified on operating income and regulatory policy issues on behalf of the Division of Public Utilities and Carriers.

Kentucky-West Virginia Gas Company (Federal Energy Regulatory Commission Docket No. RP86-52-000), February 1989. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-881125), March 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Chesapeake Utilities Corporation (Maryland Public Service Commission Case No. 8154), April 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission Docket No. R-891208), May 1989. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-891232), May 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Maryland Natural Gas and Frederick Gas Company, Inc. (Maryland Public Service Commission Case Nos. 8153 and 8155), May 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-891218), July 1989. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

The River Gas Company (Public Utilities Commission of Ohio Case No. 89-31-GA-GCR), August 1989. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination.)

Central Maine Power Company (Maine Public Utilities Commission Docket No. 89-68), August 1989. Testified on revenue, expense, rate base and income tax issues, as well as selection of proper test year on behalf of the Maine Public Advocate.

Public Service of Indiana, Inc. (Indiana Utility Regulatory Commission Cause No. 37414-S2), October 1989. Testified on rate base, net operating income, and accounting issues on behalf of the Indiana Utility Consumer Counselor.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission Docket No. RP89-49-000), December 1989 and February 1990. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

System Energy Resources, Inc. (Federal Energy Regulatory Commission), February 1990. Testified on one-eighth formula working capital requirement on behalf of the Louisiana Public Service Commission.

Bangor Hydro-Electric Company (Maine Public Utilities Commission Docket No. 90-001), June 1990. Testified on rate base revenues, expenses, sales forecasts and attrition on behalf of the Maine Public Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission Docket No. 89-057-15), July 1990. Co-sponsored testimony regarding natural gas procurement practices and policies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-901670), July 1990. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission Docket No. 90-524), September 1990. Testified on class cost of service issues on behalf of the Nevada Office of Consumer Advocate.

Central Maine Power Company (Maine Public Utilities Commission Docket No 90-076), September 1990. Testified on test year rate base, revenue and expense issues and on attrition on behalf of the Maine Public Advocate.

South Central Bell Telephone Company (Louisiana Public Service Commission Docket No. U-17949), October 1990. Testified on operating income issues and attrition on behalf of the Louisiana Public Service Commission.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. ER89-678-000), November 1990. Testified on decommissioning funding issues on behalf of the Louisiana Public Service Commission.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), November 1990. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Prior Expert Testimony

of Thomas S. Catlin

South Central Bell vs. Louisiana Public Service Commission (Nineteenth Judicial District Court, Parish of East Baton Rouge, Louisiana, Docket No. 333, 273), November 1990. Testified on overearnings of South Central Bell on behalf of the Louisiana Public Service Commission.

New Jersey Natural Gas Company (New Jersey Board of Public Utilities Docket No. GR90080786J), January 1991. Testified on cash working capital and storage inventory on behalf of the New Jersey Public Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 90-1037), February 1991. Testified on deferred fuel cost and accounting issues on behalf of the U.S. Department of Energy.

City of Great Falls Wastewater Utility (Montana Public Service Commission Docket No. 90.10.66), March 1991. Testified on cost allocation issues on behalf of the U.S. Air Force.

City of Great Falls Water Utility (Montana Public Service Commission Docket No. 90.10.67), March 1991. Testified on cost allocation issues on behalf of the U.S. Air Force.

Duquesne Light Company, Metropolitan Edison Company and Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket Nos. P-900485, P-910502 and G-900240), May 1991. Testified on behalf of the Pennsylvania Office of Consumer Advocate regarding accounting and regulatory issues in regard to the reactivation of a generating station and the transfer/sale of assets.

Bangor Hydro Electric Company (Maine Public Utilities Commission Docket No. 91-010), June 1991. Testified on test year revenue, expense and rate base and attrition issues on behalf of the Maine Public Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA89-28-000), June 1991. Testified regarding proper accounting for fees associated with the sales of accounts receivable on behalf of the Louisiana Public Service Commission.

Wakefield Water Company (Rhode Island Public Utilities Commission Docket No. 2006), July 1991. Testified regarding revenue requirements, cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

UGI Corporation (Pennsylvania Public Utility Commission Docket No. R-911973), July 1991. Testified on purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 91-5055), September 1991. Testified on rate base and net income issues on behalf of U.S. Department of Energy.

Arkansas Louisiana Gas Company (Louisiana Public Service Commission Docket No. U-19236), October 1991. Testified on rate adjustment mechanisms, private line replacement, rate design and postretirement benefits on behalf of the Staff of the Commission.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), October 1991. Co-authored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Sierra Pacific Power Company (Nevada Public Service Commission, Docket Nos. 91-7079, 91-7080 and 91-7081), November 1991. Testified on consolidated income taxes and construction work in progress on behalf of the Nevada Office of Consumer Advocate.

Sierra Pacific Power Company (Nevada Public Service Commission, Docket No. 91-7081), December 1991. Testified on water cost allocation and rate design issues on behalf of the Nevada Office of Consumer Advocate.

Louisiana Gas Service Company (Louisiana Public Service Commission, Docket No. U-19237), December 1991. Testified on test year net income, rate base and attrition issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2022), January 1992. Testified on matters pertaining to a proposed surcharge on behalf of the Division of Public Utilities and Carriers.

South Jersey Gas Company (New Jersey Board of Regulatory Commissioners, Docket No. GR91071243J), January and February 1992. Testified on rate base, operating income, and income tax issues on behalf of New Jersey Rate Counsel.

Prior Expert Testimony

of Thomas S. Catlin

Newport Water Division (Rhode Island Public Utilities Commission, Docket No. 2029), February 1992. Testified on cost allocation and rate design matters on behalf of the Division of Public Utilities and Carriers.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00912164), April 1992. Testified on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission, Docket Nos. 91-057-11 & 15), May 1992. Testified on gas procurement and gas cost issues on behalf of the Utah Committee of Consumer Services.

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19631) June 1992. Testified on rate adjustment mechanisms, rate design and postretirement benefits on behalf of the Staff of the Commission.

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 92-5), June 1992. Testified on cost allocation and rate design issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 2048), August 1992. Testified on revenue requirements, cost allocation policy and rate design issues on behalf of the Division of Public Utilities and Carriers.

US West Communications, Inc. (Utah Public Service Commission, Docket No. 92-049-05), August and October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Dallas Water Company et al. (Pennsylvania Public Utility Commission, Docket No. R-00922326 et al.), September 1992. Testified on revenue requirements and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation into Treatment of Postretirement Benefits Expense (Utah Public Service Commission, Docket No. 92-999-04), October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Prior Expert Testimony

of Thomas S. Catlin

Commonwealth Gas Services, Inc. (Virginia Corporation Commission, Case No. PUE920037), October 1992. Testified on revenue, cash working capital, weather normalization and post in service carrying charges on behalf of the Division of Consumer Counsel of the Office of Attorney General.

Entergy Corporation and Gulf States Utilities (Louisiana Public Service Commission, Docket No. U-19904), November 1992. Testified on merger related issues on behalf of the Louisiana Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-00922378), December 1992. Testified on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 92-18-GA-GCR), January 1993. Coauthored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Bossier Rural Electric Membership Cooperative (Louisiana Public Service Commission, Docket No. U-19944), February 1993. Testified on prudence standards applicable to utility decision making on behalf of the Staff of the Commission.

Consideration of Statement of Financial Accounting Standard No. 106 (Louisiana Public Service Commission, Docket No. U-20181), February 1993. Testified on regulatory issues related to adoption of SFAS No. 106 for ratemaking on behalf of the Staff of the Commission.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00922476), March 1993. Testified on rate base and net income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission, Docket No. 92-121022), April 1993. Testified on class cost of service and rate design on behalf of the Nevada Office of Consumer Advocate. (Case settled prior to cross examination.)

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 92-345), May 1993. Testified on test year net income and rate base and attrition issues on behalf of the Staff of the Maine PUC.

Prior Expert Testimony

of Thomas S. Catlin

Dauphin Consolidated Water Supply Company and General Waterworks of Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00932604), June 1993. Testified on rate base, income tax and class cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Kent County Water Authority (Rhode Island Public Utilities Commission, Docket No. 2098), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission, Docket No. RP92-73-000), July 1993. Testified on rate base and revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

City of Woonsocket Water Department (Rhode Island Public Utilities Commission, Docket No. 2099), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00932548), July 1993. Testified on income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Conestoga Telephone & Telegraph Company (Pennsylvania Public Utility Commission Docket No. I-00920015), September 1993. Testified on revenue expense and rate base issues as well as proper average schedule separations procedures on behalf of the Pennsylvania Office of Consumer Advocate.

The Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 93-14-GA-GCR), October 1993. Co-authored report on the audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

The Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. P-00930715), December 1993. Testified on historical and projected earnings levels and earnings monitoring in conjunction with alternative regulatory plan on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932670), February 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932868), April 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Southwest Gas Corporation - Southern Arizona Division (Arizona Corporation Commission, Docket No. U-1551-93-272), May 1994. Testified on revenue and rate base issues on behalf of the Staff of the Arizona Corporation Commission. (Case settled prior to cross-examination)

Commonwealth Edison Company (Illinois Commerce Commission, Docket No. 94-0065), June 1994. Testified on nuclear decommissioning funding on behalf of the U.S. Department of Energy.

West Penn Power Company (Pennsylvania Public Utility Commission Docket R-00942986), July 1994. Testified on net income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

City of Bethlehem-Bureau of Water (Pennsylvania Public Utility Commission, Docket No. R-00943124), October 1994. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

General Waterworks of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00943152), October 1994. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Gas & Oil Corporation (Public Utilities Commission of Ohio, Case No. 94-221-GA-GCR), October 1994. Co-authored report on the audit of the management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without hearings.)

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19997), November 1994. Testified on the costs properly included in the weighted average cost of gas of Louisiana Intrastate Gas Corporation and the purchased gas adjustment of Trans La on behalf of Staff of the Commission.

Prior Expert Testimony

of Thomas S. Catlin

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket Nos. RP91-203-000 and RP92-132-000, Phase II-PCB Issues), December 1993. Testified on cost of PCB remediation in current dollars and percentage allowance applicable to claimed PCB costs on behalf of the Pennsylvania Office of Consumer Advocate and the Ohio Office of the Consumer's Counsel. (Case settled prior to cross-examination.)

New England Telephone and Telegraph Company (Maine Public Utilities Commission, Docket Nos. 94-123 and 94-254), December 1994. Testified on Process Re-engineering (downsizing) costs and benefits and on attrition issues on behalf of the Maine Public Advocate.

Louisiana Power & Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Testified on rate base and operating income on behalf of the Staff of the Public Service Commission.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00943231), February 1995. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

NorAm Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP93-343-000), March 1995. Testified on rate base, operating expense and income tax issues on behalf of the Arkansas Public Service Commission and the Louisiana Public Service Commission. (Case settled prior to hearings.)

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 94-164), March 1995. Testified on cost allocation, rate design and monthly billing issues on behalf of the Staff of the Public Service Commission. (Case settled prior to cross-examination.)

Pennsylvania Power & Light Company (Pennsylvania Public Utility Commission, Docket No. R-00943271), April 1995. Testified on operating income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-953299), June 1995. Testified on revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2304), July 1995. Testified on water consumption and cost allocation/rate design issues on behalf of the Division of Public Utilities and Carriers.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112-000), September 1995. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examinatin.)

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP95-197-000), January 1996. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Frontier Communications of Pennsylvania, et al. (Pennsylvania Public Utility Commission, Docket No. P-00951005), May 1996. Testified regarding financial issues and operational aspects of Companies' proposal to implement a streamlined form of regulation (price cap) on behalf of the Pennsylvania Office of Consumer Advocate.

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963550), May 1996. Testified on financial issues, revenue growth, and capital expenditures in conjunction with Bell Atlantic-Pennsylvania's proposal to rebalance rates. Testimony filed on behalf of the Pennsylvania Office of Consumer Advocate.

Petition of AT&T Communications of Pennsylvania for Arbitration of its Interconnection Request to Bell Atlantic-PA (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Sponsored position of Pennsylvania Office of Consumer Advocate on resale discount, 900 number call billing, network interface devices, and unbundled loop rates in arbitration hearings.

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963578), September 1996. Testified regarding the determination of the appropriate resale discount for Bell Atlantic-Pennsylvania on behalf of the Pennsylvania Office of Consumer Advocate.

Pacific Bell Communications, Inc. (Public Utilities Commission of the State of California, Docket No. 96-03-007), October 1996. Testified on affiliate relationship issues under Section 272 of the Telecommunications Act of 1996 on behalf of the California Cable Television Association.

Prior Expert Testimony

of Thomas S. Catlin

West Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 96-221-GA-GCR), November 1994. Co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Application of MFS Intelenet of Pennsylvania, Inc. et al. (Phase III) (Pennsylvania Public Utility Commission Docket No. A-310203F0002 et al.), January 1997. Testified on loop cost issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission Docket Nos. RP91-203-062 and RP92-132-049), March 1997. Testified on ratemaking treatment of New England laterals on behalf of the Tennessee Rate Design Customer Group.

Frontier Communications of Oswayo River, Inc. (Pennsylvania Public Utility Commission Docket Nos. C-00957322 and C-00957324), May 1997. Testified on EAS rate issues on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-00973953), June 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Transcontinental Gas Pipeline Corporation (Federal Energy Regulatory Comission Docket No. RP97-71-000), June 1997. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

OCA Statement No. 3-S

8/27/97
Hearing
w/H

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER	)	
	)	
&	)	DOCKET NO. R-00973954
	)	
LIGHT COMPANY	)	

SURREBUTTAL TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 1997

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00973954

Surrebuttal Testimony of Thomas S. Catlin

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of the Pennsylvania Office of Consumer Advocate (OCA) which has been identified as OCA Statement No. 3. My qualifications and experience are presented in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to certain issues raised by Pennsylvania Power and Light Company (PP&L or the Company) in its rebuttal testimony. In particular, I will respond to the rebuttal testimony of Mr. Joseph R. Schadt with regard to Susquehanna deferred fuel costs and Mr. Joseph Kleha with regard to unrecovered energy costs.

Q. ARE YOU PROPOSING TO MAKE ANY CHANGES TO THE RECOMMENDATIONS WHICH YOU PRESENTED IN YOUR DIRECT TESTIMONY?

A. No. I am not proposing any modifications to my recommendations regarding regulatory assets or decommissioning costs. I would note that one of the adjustments which I made in my direct testimony was to eliminate the DOE assessment from regulatory assets because that assessment was already accounted for as part of fuel costs. In its rebuttal testimony, PP&L removed the DOE assessment from its nuclear fuel costs in order to eliminate the double count. Because the DOE assessment has not been removed from the OCA's nuclear fuel costs, I have continued to exclude the DOE assessment from my quantification of regulatory assets.

Susquehanna Deferred Refueling Costs

Q. WHAT POSITION HAS PP&L TAKEN WITH REGARD TO DEFERRED REFUELING OUTAGE COSTS IN ITS REBUTTAL TESTIMONY?

A. PP&L has continued to propose that it be allowed to include deferred refueling costs as a regulatory asset. The primary argument for this appears to be that PP&L has historically been allowed to recover these costs after they are incurred over the 18-month interval between outages.

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH PP&L'S POSITION.

A. As indicated by Mr. Schadt in his rebuttal testimony, PP&L has been allowed to normalize refueling outage costs for ratemaking purposes by amortizing those costs over the outage interval. For example, in the Company's last rate case in Docket No. R-00943271, the normalized level of refueling outage costs was determined based on an 18-month amortization of the costs of the most recent outage at each unit. Under this approach, the costs of each outage have been and are recovered prior to the completion of the next outage. This is, in fact, shown on Mr. Schadt's rebuttal Exhibit JRS-6.

The procedure of amortizing the cost of an outage over the outage interval is necessary to match the costs of the outage to the period to which the costs apply.[1] As a result of these procedures, which have been followed for both accounting and ratemaking, both book and ratemaking expenses include a normal, annualized level of refueling outage expense. Accordingly, there is no need or basis for including the unamortized balance of refueling costs as of December 31, 1998 as a regulatory asset. Including the unamortized balance as a regulatory asset as PP&L has proposed would result in $9.55 million of refueling outage costs being double counted.

Unrecovered Energy Costs

Q. PLEASE SUMMARIZE THE ISSUE WHICH EXISTS WITH REGARD TO UNRECOVERED ENERGY COSTS.

A. As part of its stranded cost claim, PP&L has included $31.5 million per year in 1997 and 1998 for unrecovered energy costs. This claim reflects the difference between the average energy costs in the years 1992-1996 and the level of energy costs rolled into base rates on January 1, 1997. Both the OCA and the PP&L Industrial Customer Alliance (PPLICA) filed direct testimony opposing the inclusion of this projected energy cost underrecovery as a stranded cost, generally for the reason that PP&L has not demonstrated that it will actually underrecover its energy costs.[2] In response to these recommendations, Mr. Kleha has filed new projected cost data for 1997 and 1998 attempting to show that the Company's energy

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[1]The costs of a refueling outage clearly apply to the period following the outage since there were no outage costs to recover prior to the first outage when the unit went into service and the last refueling outage will occur prior to the time the unit is retired.

[2]This issue is discussed in detail at pages 6-8 of the direct testimony of Richard La Capra (OCA Statement No. 1), pages 5-7 of my direct testimony (OCA Statement No. 3) and pages 17-21 of the direct testimony of Lane Kollen (PPLICA Statement No. 3).

cost underrecoveries will be even greater than those claimed based on average costs in 1992 through 1996.

Q. HAVE YOU REVIEWED MR. KLEHA'S PROJECTIONS OF FUEL COST UNDERRECOVERIES IN 19997 AND 19998?

A. Given the time limitations between the filing of rebuttal and surrebuttal, it was not possible to conduct discovery with regard to the projections which Mr. Kleha filed. Therefore, my review was limited to the information presented in Exhibit JMK-6.

Q. ARE THE PROJECTED UNDERRECOVERIES LIKELY TO BE ACCURATE?

A. No. Mr. Kleha's projections include a number of significant assumptions which are likely to cause these projections to be inaccurate. For example, Mr. Kleha's projections reflect increases in the level of fuel costs due to changes in the number of kWh sold. However, no increases in revenues due to increases in kWh sold have been recognized. That is, the Company's projections assume that the absolute amount of energy revenues is fixed. In addition, there is a significant (11%) decline in the projected level of nuclear generated energy from 1996 to 1998, despite the fact that each year from 1996 through 1998 includes an outage. This is material because nuclear generation is PP&L's least expensive source of energy other than hydropower. PP&L's projected underrecoveries also reflect sizable swings in purchased power quantities and off-system sales to other utilities from 1996 to 1998.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. KLEHA'S REBUTTAL TESTIMONY ON THE ISSUE OF UNRECOVERED ENERGY COSTS?

A. Yes. In his rebuttal testimony, Mr. Kleha indicates that I have asserted that PP&L's claim for unrecovered energy costs for 1997 and 1998 should be denied because the Company's pro forma return on equity may be understated. This is a mischaracterization of my direct testimony. As discussed in more detail at pages 5-7 of my direct testimony (OCA Statement

No. 3), what I have asserted is that the Commission should not prejudge or conclude in advance that PP&L's rates are not adequate to recover its total energy costs. Now that energy costs are being recovered in base rates, PP&L should not be allowed to defer energy costs in 1997 and 1998 without demonstrating that its existing rates are inadequate to recover its existing costs.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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