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R-943271

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket Number: R-00943271

Direct Testimony of Eugene M. Brady

COMMISSION ON ECONOMIC OPPORTUNITY
OF LUZERNE COUNTY

Concerning:

Other Issues

April 14, 1995

Q. Please state your full name and business address.

A. Eugene M. Brady, 211 South Main Street, Wilkes-Barre, Pennsylvania 18701.

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

A. I am employed by the Commission on Economic Opportunity (CEO) as Executive Director.

Q. What are the interests of the Commission on Economic Opportunity in this rate case?

A. The Commission on Economic Opportunity is a non-profit organization serving the low income and elderly in Luzerne County, PA. It is a part of our responsibility to our constituency to advocate for their interests within the bureaucracy and PP&L's proposed rate increase falls disproportionately on residential ratepayers in general, and low income ratepayers in particular. I intend to address several issues. First, PP&L's proposed "Social Programs" and its current Low Income Usage Reduction Program benefit electric heat and electric hot water customers and not those who will bear the largest percentage increase under the proposed rates, electric baseload customers. Secondly, PP&L residential demand side management programs, as proposed, are designed to attract new customers and do little, if anything, to reduce the energy burden of existing ratepayers. And in addition, both current and proposed programs are not made available proportionately across the PP&L Regions.

Our position in this case is not necessarily that the increase is unacceptable per se: we understand that in today's environment PP&L must position itself to become competitive. Our concern is to insure that the low income and the elderly have the ability to cope with their payment responsibilities. In the event of a 20% residential rate increase, which is what the majority of baseload customers will pay under this request, there would have to be additional assistance to lessen the burden on this category of customer.

Q. What background and experience in energy issues qualify you and the Commission on Economic Opportunity to make these arguments?

A. I have served as the Executive Director of the Commission since 1978. During my tenure the Commission's experience and the expertise of its staff in energy programs has been recognized on state and national levels and the Commission's Programs have been acknowledged by receipt of a Superior Achievement Award from the United States Department of Energy. The Commission has weatherized 23,000 homes under the U.S. Department of Energy Weatherization Assistance Program. The organization also serves as a subcontractor for the Pennsylvania Power and Light Company's WRAP Program and the Low Income Usage Reduction Programs operated by the Pennsylvania Gas & Water Company and UGI Gas and Electric Divisions. Through the utility companies programs, more than 5,000 homes in Luzerne, Schuylkill, Carbon, Monroe, Pike, Northumberland and Wayne Counties have been weatherized by the Commission on Economic Opportunity.

The Commission was the first agency in Pennsylvania to launch a full scale furnace modification program and subsequently provided training statewide to assist other organizations in implementing a similar program. The Commission organized and presented training sessions for Energy Assistance Providers in the Mid-Atlantic Region on innovative approaches to serving the low income population. The Commission also, under contract with the Pennsylvania Department of Public Welfare, trained service providers statewide in community network development, resource mobilization and program implementation for the Low Income Home Energy Assistance Program.

The Commission was the first in Pennsylvania to develop a model Energy Conservation Education Program including the curriculum and program materials, most notably, a 15 minute videotape highlighting Energy Education practices which can reduce energy consumption.

In conjunction with the Pennsylvania Department of Community Affairs, the Commission organized and delivered a training conference on Energy Conservation and Energy Education for utility companies and Weatherization providers statewide. In addition to organizing and presenting conferences and workshops, the Commission's expertise has been recognized by invitations to present workshops and panel discussions from numerous state and national groups. These include: the U.S. Department of Energy, the Pennsylvania Public Utility Commission, Pennsylvania Energy Center, Region X, Pennsylvania Petroleum Association, the National

Association of Community Action Agencies, Pennsylvania Electric Association, and the Weatherization Training Center.

The Commission on Economic Opportunity has also successfully competed and been awarded several pilot and demonstration projects. Under the auspices of the Pennsylvania Energy Office and the U.S. Department of Energy, the Commission utilized state-of-the-art analytical and diagnostic audit and thermography technology at a time when this Blower Door technology was just being developed at Lawrence Berkeley Laboratories. The House Doctor Demonstration Project was designed to determine the cost of effectiveness of diagnostic/analytical weatherization and to demonstrate the results achievable using the advanced technology to enhance the existing standard methods of weatherization. The results of this project have been widely distributed and well received. They have been responsible for the incorporation of these techniques into the statewide weatherization program and most of the Public Utility Commission's Low Income Usage Reduction Programs.

Q. Does your personal background include exposure to Demand Side Management and energy issues on a statewide and national level?

A. Throughout my career I have served on numerous Boards, Committees and Task Forces in this field. Presently, I serve on the Board of Directors of the National Center for Appropriate Technology, the U.S. Department of Energy National Work Group on Single Family/Multi-Family Dwellings; I am on the Board of the National Community Action Foundation, the Chair of the Pennsylvania Weatherization

Providers Task Force, on the Board of the Pennsylvania Energy Assistance and Weatherization Coalition and Vice-Chair of the Department of Community Affairs Weatherization Policy Advisory Council.

Q. Mr. Brady, would you address your concerns regarding the social programs as proposed by PP&L?

A. I will first state that PP&L should be commended for its initiative in proposing these programs, and the Task Force which developed the programs for recommending that they be implemented regardless of the outcome of the rate case. This acknowledges the fact that a corporation has a social responsibility to the community at large, regardless of whether it is requesting a rate increase. We support these programs, but need to be assured that they are not merely window dressing and exist only on paper. There must be a corporate commitment from the shareholders and Senior Management to implementing *PP&L Partners: Communities in Action.* The commitment must go beyond the corporate marketing and public relations incentives that programs of this type usually offer to shareholders and management.

Q. What recommendations would you make to insure that these programs meet their intended objectives?

A. Current social program funding projections indicate that the company plans to spend $6.7 million a year for the next five years, a total of $33.5 million. This is a recommendation that is not contingent upon a rate increase. Therefore, if a rate increase is granted. the funding level should increase. I would recommend, in the event that the rate increase is granted, that funding levels be increased gradually over the course of five years:

1st Year	$ 6.7 million
2nd Year	$ 8.0 million
3rd Year	$ 9.7 million
4th Year	$11.6 million
5th Year	$13.4 million

In that the programs were developed by a Task Force which consisted of in-house staff, and the community input was limited to a telephone survey of needs and priorities in local communities, community organizations need to be more actively involved in both the planning and implementation of these programs. The Pennsylvania Power & Light Company is a public utility and, as such, its management philosophy and staff expertise lies in the generation and distribution of energy. The role of the corporation in implementing these programs should be one of administration, monitoring and inspection. The expertise in developing and operating programs which benefit people and communities lies within community based organizations. That is, the research and development for these projects should occur on a community level, by organizations who are experienced in these programs not on a PP&L staff level.

While PP&L has stated that they have not decided the details of the new programs in order to maximize their effectiveness in the local communities, I feel certain program details need to be established through the rate-making process because past experience with the company and its "social programs" has shown that the initial intentions and outlines presented as part of rate hearings become operational in very company centered ways. "Social programs" have been used many times by the company to lessen the impact of corporate reductions in force. In several instances, staff cutbacks have caused the company to discontinue contracts with community organizations and replace these contracts with in-house staff who are not trained to perform these tasks and who would have, otherwise, been laid off. In developing the operational details for these programs, the company works actively with community organizations who invest a great deal of time and effort in planning, with no reimbursement, then the company pulls the program in-house. The corporate commitment must be to assist local communities and their residents and secure the most cost-effective value for the funds being expended. These are "people" programs, not public relations programs, and community based organizations are best qualified to implement them.

In order to maximize the effectiveness of both the Build-A-Neighborhood and the Affordable Housing components, the funds appropriated by PP&L should be in the form of a Block Grant. In this way these funds may be used by community based organizations to leverage government programs for community development and they can very effectively complement the governmental funds. Each community differs in the ways it allocates Federal and state funds, some actively subsidize affordable housing, some only provide infrastructure programs. To be most effective. PP&L should enable the funds to be used to bridge the gaps in existing community development funding, which would differ from community to community.

PP&L can also encourage innovation and creativity by funding demonstration projects which address unique needs. Many times this process results in outstanding and unusual ways of improving community life.

Q. In your judgement are these programs sufficient to relieve the burden that the rate increase, as proposed, will place on the low income, working poor and the elderly?

A. As presented, the programs outlined can have an impact on households that use electricity for space heating, because weatherization and energy conservation education are significant parts of several of the programs. However, these do very little to address the burden that a rate increase will impose on the low income and elderly **baseload** customer. Baseload customers will have the largest percentage increase in their bills. PP&L's projections indicate that customers utilizing 500 kWh will see a 20.7% increase. Winter Emergency, Payment Protection, Operation HELP Contribution and CARES Extension Programs, while they will offer some assistance in unusual circumstances, they are primarily directed toward insuring that PP&L gets paid when the circumstances occur. They do not address baseload consumption.

Baseload conservation, with the exception of compact florescent lamps, has been neglected thus far by PP&L. The advent of weatherization and energy conservation education has resulted in a drop in consumption for heating use. but baseload consumptionn continues to increase. In the interests of both Integrated Resources Planning and in order to provide some relief for low income customers. the Pennsylvania Power & Light Company should direct resources into baseload conservation measures as an integral component of Demand Side Management Programs. Energy efficiency improvements are an excellent way to mitigate rate impacts on all ratepayers. The PP&L resources allocated to Demand Side Management are inadequate overall. but the deficiency is most obvious when one compares the resources directed toward programs available to existing ratepayers versus the resources directed toward acquiring new ratepayers. The overwhelming proportion is clearly directed to new home building programs and other programs which require a substantial investment of capital. The elderly and the working poor. unable to acquire the capital. are effectively excluded from participating in any of these programs.

Providing development costs to community organizations to develop pilot and demonstration programs which can result in a prescriptive approach to baseload management. as was done in by major utility companies in Wisconsin. will result in marked improvements in the body of knowledge which presently exists on baseload management. These pilot programs will enable PP&L to reduce the impact of the proposed rate increase and move forward with enlightened Demand Side Management Programs.

Q. Do you have concerns regarding the mechanism used by PP&L in distributing funds for community programming throughout its five regions?

A. Yes. prior to 1993. PP&L had six divisions and all corporate funds. Operation HELP. WRAP. etc. that went to community groups either to purchase services or to assist customers in paying energy bills appear to be divided equally among the six divisions. In 1993. the Northern (Scranton) Division and the Central (Wilkes-Barre/Hazleton) Division were merged and became the Northeast Region. The funds are now proposed to be divided equally among the five regions. with no consideration given to the fact that previously the Northern and Central Divisions had received 1/3 (2/6) of the funds. and are now receiving 1/5 as the Northeast Region.

In terms of ratepayer demographics. low income electricity consumption and heating degree days. of PP&L's five regions. the Northeast Region will suffer most from the rate increase.

The Northeast Region contains:

- 27% of PP&L's 150% of poverty households: more than 1 ¼ times the territorial average.
- 26% of PP&L's elderly population: more than 1 ¼ times the territorial average.
- 25% of PP&L's disabled population; more than 1 ¼ times the territorial average.
- 24% of PP&L's poverty households with children: about 1 ¼ the territorial average.

- In Heating Degree Days, the Northeast Region is 1½ times colder than the territorial average.

It would be more equitable to base the distrbution of funds on the factors that the funds are intended to address: the funds should be distributed based upon poverty population, the percentage of elderly and heating degree days.

Q. Does this conclude your testimony?

A. Yes, it does.

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PENNSYLVANIA POWER & LIGHT COMPANY

Docket Number: R-00943271

Direct Testimony of Craig R. Kuennen

COMMISSION ON ECONOMIC OPPORTUNITY
OF LUZERNE COUNTY

Concerning:

Other Issues

April 14, 1995

Q: **Please state your full name and business address.**

A: Craig R. Kuennen. 211 South Main Street. Wilkes-Barre. Pennsylvania 18701.

Q: **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A: I am employed by the Commission on Economic Opportunity (CEO) as Energy Services Manager.

Q: **WHAT ARE YOUR RESPONSIBILITIES AS ENERGY SERVICES MANAGER?**

A: As Energy Services Manager. I am responsible for expanding the resources available to meet the energy service needs of low income and working poor in CEO's service area. This includes the analysis of proposed and existing energy services programs offered to the community. The goal is to identify efficiencies that can improve the total level of services offered.

Additionally, I am responsible for developing new energy programs and funding sources to address the needs within the community. Activities in support of these responsibilities include the design of energy programs in response to government and utility Request For Proposals (RFPs). and in depth analysis of various regulated utility energy program proposals such as Demand Side Management (DSM) programs. Low Income Usage Reduction Programs (LIURP). and Customer Assistance Programs (CAP).

Q: **WHAT IS YOUR EDUCATIONAL BACKGROUND?**

A: I graduated summa cum laude from National University, San Diego, California with a Bachelor of Business Administration Degree in 1987, and went on to earn a Masters Degree in Business Administration with an emphasis in Financial

Management from National University in 1988. In 1989, I entered the Philosophy program at San Diego State University, San Diego, California, where I concentrated my studies in the areas of Social Ethics and Philosophy of Technology. I received a Master of Arts Degree in Philosophy in 1992. I am currently a Ph.D. (abd) Candidate at the University of Delaware, College of Urban Affairs and Public Policy, Center for Energy and Environmental Policy, Newark, Delaware. My studies at the Center for Energy and Environmental Policy have focused on how different interpretations of efficiency lead to public and corporate policies that result in technological design choices that harbor within them vastly different social and environmental consequences.

Q: **HOW LONG HAVE YOU BEEN EMPLOYED BY CEO AND IN WHAT CAPACITIES?**

A: I came to work at CEO in June 1993 as a graduate intern. In June 1994, I joined on full time as CEO's Energy Services Manager. During my stay at CEO, I have been involved in the analysis of several government and regulated utility energy conservation programs. I was directly responsible for researching energy education programs offered nationally through utility demand side management and government funded weatherization programs in order to upgrade CEO's energy education program.

Additionally, I have been called upon review, analyze, and make recommendations for improving Customer Assistance Programs (CAPs) submitted to CEO for review and comment by Pennsylvania Power & Light Company and Pennsylvania Gas and Water Company. In response to a Request For Proposal, I designed an energy survey for Pennsylvania Gas & Water for use in developing its Integrated Resource Plan.

During the past six months, the bulk of my time has been spent researching demand side management. CEO is interested in DSM because, in light of the PPUC's December 1993 ruling authorizing DSM cost recovery, DSM represents a potentially growing energy service area in the Commonwealth. And, as a community based organization, we are particularly concerned that the Commonwealth's DSM portfolio grow in such a way that it includes the people we represent in the Community. In this light, we are particularly concerned that the Commonwealth's DSM portfolio grow in terms of total funding and programs diversity so that it includes programs that directly benefit residential baseload and small industrial and commercial customers, and that mechanisms are developed to include the elderly, low income, and working poor ratepayers.

Currently, PP&L's DSM portfolio favors certain ratepayers over others. We feel strongly about this issue because those ratepayers who directly participate in demand side management programs receive a considerably higher return for the DSM investment than non-participants. These inequalities will be magnified if PP&L's rate increase goes into effect without remedy. One way to mitigate past DSM programs bias' and provide relief from any rate increase with minimal overall rate impact is to require PP&L to increase its total DSM program spending and to require that that funding go toward developing programs targeting previously neglected groups.

Q: **MR. KUENNEN, PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.**

A: I will address four demand side management issues in my testimony. First, I will discuss PP&L's overall demand side management (DSM) philosophy. Second, I will discuss inequalities present in PP&L's demand side management portfolio with specific reference to inequalities that exist between new and existing ratepayers, and between ratepayers within the same customer classes. Third, I will discuss how PP&L's DSM philosophy may be contributing to an artificially low level of demand side management spending in PP&L. Fourth, I will discuss the need for the Pennsylvania Public Utility Commission to set minimum demand side management funding and program diversity targets to promote equality between demand and supply side resource options, and between ratepayers within customer classes in order to address past bias' and the impact of any rate increase.

Q: **WHAT IS PP&L'S STATED DEMAND SIDE PHILOSOPHY?**

A: After considerable review of PP&L's *Demand Side Management Program March 1994 Filing* and the materials offered by PP&L in support of its rate increase request, the most definitive statement I found describing PP&L's DSM philosophy is Exhibit DAK 1, 1994-1995 Construction Budget. Beginning on page 3-4 and continuing on page 3-5, DAK 1 states that

> DSM represents an important element of PP&L's strategy to meet customer electric energy needs. DSM helps achieve long-term corporate objectives to maintain base rate stability, provide a fair return on common equity, and defer the need for additional central station generation. . . . PP&L's DSM objectives will continue to be to design and implement programs that: promote the profitability and comfort of our customers by meeting their electric energy needs, increase sales (within the overall policy objectives of

the PPUC to manage demand). defer more costly supply-side resources. and increase both supply and end-use efficiencies.

Q: **In practice. how does PP&L's stated DSM philosophy compare with its concrete programs?**

A: PP&L's stated philosophy suggests that PP&L views DSM as a legitimate demand and energy resource. and as something that all raterpayers have some access to direct program benefits. Its DSM portfolio looks somewhat different from its stated position. Though sales promotion or load building is included as a goal in PP&L's stated DSM philosophy. it appears as but one goal among many. In PP&L's March 1994 DSM filing, sales promotion appears as the primary. if not. single goal. This leads me to believe that PP&L sees DSM primarily as a sale promotion tool and not as a demand and energy resource.

Q: **Has this lead to inequalities in PP&L's DSM portfolio?**

A: I think so. PP&L's March 1994 DSM Filing shows a clear bias toward programs designed to increase and/or maintain sales. This is particularly evident with respect to residential DSM programs and expenditures. Nearly 95% of PP&L's residential DSM dollars support programs that promote electric heat in the new home construction market. and nearly 100% of its residential DSM programs require ratepayers to have electric heat in order to participate. This means that approximately 70% of PP&L's residential ratepayers. those baseload only customers. have no direct access to the DSM program benefits which they are required to pay for in their rates. This is despite the fact that a wide variety of industry proven programs are available to PP&L for inclusion in its DSM portfolio at costs comparable to PP&L's current 3.0¢/kWh incremental cost of energy as reported in its March 1994 DSM filing.

In terms of PP&L's proposed industrial and commercial programs. 100% of these programs are geared toward large industrial and commercial customers who in the market for a cheaper energy rate. capital intensive equipment. and/or a new building or major renovation. There are no programs that directly benefit small commercial and industrial customers even though they are required to pay DSM program costs.

Q: DOES PP&L'S DSM PHILOSOPHY ARTIFICIALLY LIMIT ITS POTENTIAL AS DEMAND AND ENERGY RESOURCE?

A: Yes. I think so. When DSM is primarily viewed as a sales promotion or market maintenance tool instead of a demand and energy resource. I would expect the utility's DSM portfolio to be limited in funding relative to some standard and to disproportionately favor certain ratepayers within classes over others. There would be few. if any. programs targeting residential baseload customers because they are seen as a captive market that need not be addressed. Similarly. there would be few. if any. programs targeting small industrial and commercial customers because. in the absence of retail wheeling and/or access to NUG services. these customers are similarly captive. As for existing residential electric heat customers and medium sized industrial and commercial ratepayers. since only a limited number of this customer base would be in the market for end-use efficiencies, there may be limited program access for these groups.

The bulk of the DSM portfolio would contain programs targeting new home construction. This is where the battle over the initial home heating fuel choice is waged, and the place where marketing campaigns can have the most effect. Additionally, I would expect that funding for these programs would be linked to the number of new housing starts projected in the coming years, and to some assessment as to how many of these new units could be converted to electric heat. With respect to the industrial and commercial classes, I would expect to see programs that target customers in the financial position to entertain alternative energy supply sources.

PP&L's Demand Side Management March 1994 Filing fits this description quite well. The lack of an adequate cost recovery mechanism can explain some of PP&L's relatively low total DSM funding and lack of program diversity in the past, but with the PPUC's December 13, 1993 adoption two cost recovery options, it cannot explain the lack of additional funding and program diversity present in its March 1994 DSM filing.

Q: **WOULD YOU ELABORATE ON THIS CONCLUSION?**

A: We can get a sense of the adequacy of PP&L's total DSM spending by comparing PP&L's DSM expenditures to those of industry and in the states surrounding Pennsylvania. As for the lack of program diversity, this is a social equity issues that can be address by comparing the target markets of the programs in PP&L's March 1994 DSM Filing with its customers base which I have already addressed.

There are at least four ratios that can be used to gauge a utility's commitment to DSM. The first is the ratio of demand side management spending to retail revenues. When compared to other utilities and the industry average, this ratio gives us a glimpse as to the adequacy of the utility's total DSM spending. The second ratio is that of DSM spending to new construction spending. This ratio offers a glimpse as to how well DSM options fair in the utility's integrated resource planning process compared to supply side options. The third and fourth ratios compare DSM "equivalent capacity" to peak demand capacity requirements, and DSM energy savings to peak demand energy requirements. As with the new construction ratio, these last two ratios give us a glimpse as to how well DSM options fair in the utility's integrated resource planning process compared to supply side options, and the level of commitment the utility has to pursuit of end-use energy efficiencies.

Low ratios suggest that the utility might be just beginning to develop its DSM options, or that its places a low priority on DSM as a demand and energy resource in its integrated resource planning process. This low priority could be the result of the utility's philosophical position with respect to DSM or because adequate cost recovery mechanisms and/or adequate DSM spending and program targets are not in place to encourage DSM development.

Q: **HOW DOES PP&L COMPARE TO OTHER UTILITIES AND THE INDUSTRY WITH RESPECT TO THESE AVERAGES?**

A: Based on PP&L's March 1994 DSM filing, PP&L planned on spending approximately 0.4% of retail revenues for the years 1994, 1995, and 1996. This ratio is about one third of the 1.5% national average for these years as reported in Stan Hadley and Eric Hirst's February 1995 Oak Ridge National Laboratory report *Utility DSM Programs From 1989 Through 1998: Continuation or Cross Roads?* and well below the 1993 spending level of at least four PJM utilities serving Maryland and New Jersey. In 1993, Potomac Electric spent about 4.3%, Baltimore Gas & Electric's spent 3.1%, Public Service spent 1.4%, and JCP&L spent about 1.8%.

In terms of new construction spending, the 1991 top twenty DSM utilities had DSM expenditures equal to 14.4% of new construction expenditures based on Energy Information Administration data. Potomac Electric and Public Service Electric & Gas, both PJM utilities, DSM spending was 6.0% and 4.0% of new construction in 1993. A third PJM utility, Baltimore Gas & Electric, had DSM expenditures of 10.6%, 18.3%, 20.9% of new construction expenditures in the years 1992, 1993, and 1994. In comparison, PP&L DSM expenditures were considerably less at 2.9%, 2.6%, 2.5%, and 2.4% of new construction expenditures during the years 1991, 1992, 1993, and 1994.

As for DSM capacity equivalent to peak demand capacity requirements, PP&L's DSM demand side management resources accounted for approximately 3.2% of PP&L's needs in 1993. The 1993 industry average according to Hadley and Hirst was about 6.4%. As for PJM utilities in 1993, Potomac Electric's DSM program accounts for approximately 6.5% of its peak demand requirements.

Baltimore Gas & Electric DSM accounts for 8.9%. and Public Service DSM accounts for about 6.0%. I currently have no data on JCP&L for this ratio.

In terms of DSM energy savings to energy sales. PP&L's DSM energy savings were approximately 0.5% of PP&L's energy sales in GWH in 1993. and 0.6% in 1994. This is considerable below the industry average of 6.0% in 1993. and 7.2% in 1994 according to Hadley and Hirst. Similarly, this is well below the 1993 ratios of three PJM utilities which I have data on. Potomac Electric DSM energy savings were 6.5% of GWH sales in 1993. Baltimore Gas & Electric energy savings were 8.9% of GWH sales. and Public Service energy savings were about 6.0% of GWH sales.

Q: **OTHER THAN COST RECOVERY MECHANISMS, ARE THERE ARE WAYS TO ENCOURAGE PP&L TO DEVELOP ITS DEMAND SIDE MANAGEMENT RESOURCES BOTH IN TOTAL FUNDING AND PROGRAMS DIVERSITY?**

A: Yes, data on demand side management activities is readily available to agencies such as the Pennsylvania Public Utility Commission. The DSM data used in Hadley and Hirst study I mentioned earlier comes from the Energy Information Administration Form EIA-861. The PPUC's Bureau of Conservation. Economics. and Energy Planning could use this and other data to produce a set annual demand side management funding. demand savings, and energy savings targets for Pennsylvania electric utilities based on at least four Industry. MAAC. and/or PJM DSM ratios. These four ratios. at a minimum. be used to set DSM funding, demand savings, and energy savings targets:

- Annual DSM spending to annual retail revenues
- Annual DSM spending to annual new construction expenditures
- Cumulative DSM demand "capacity" to Peak Demand Requirements
- Cumulative DSM Energy Savings to Annual Energy Demand.

Q: **WHY NOT USE PENNSYLVANIA DATA TO GAUGE THE ADEQUACY OF PP&L'S DEMAND SIDE MANAGEMENT PORTFOLIO IN TERMS OF FUNDING, DEMAND AND ENERGY SAVINGS, AND PROGRAM DIVERSITY?**

A: Ultimately, I would think the goal is bring Pennsylvania electric utility DSM programs in line more experience DSM utilities in the surrounding states and the industry as a whole. As such, Pennsylvania ratios should only be used to gauge the progress of the Commonwealth's DSM Portfolio vis a vis that of surrounding states and the industry as a whole. To ask PP&L, and other electric utilities in the Commonwealth, to meet DSM target based on Pennsylvania ratios would do little if anything to encourage better integration of demand side management in the integrated resource planning process in Pennsylvania. By the Pennsylvania standard, PP&L would be considered an aggressive demand side management utilities. By the industry standard, we get a different picture.

In 1993, Pennsylvania ranked in the bottom in three categories. Pennsylvania DSM spending was less than 0.5% of annual retail revenues. Eleven states were spending more that 2.0%. Cumulative Pennsylvania DSM "capacity" was less than 0.5% of peak demand. Seven had DSM capacity greater than 10.% of peak demand, and nine state came in at 8-10%. Finally, in terms of GWH sold, Pennsylvania

DSM programs saved less that 0.5% of total sales in 1993. In fourteen states, DSM energy savings equaled more that 2.0% of total sales.

Q: **HAVE YOU GIVEN ANY THOUGHT TO WHAT PP&L'S DSM TARGETS SHOULD BE?**

A: Yes. I would set annual DSM spending targets in terms of retail revenues at 0.75-1.0% in 1996. 1.0-1.5% in 1997. 1.5-2.0% in 1998. 2.0-2.5% in 1999. and 2.5-3.0% in the year 2000. This would result in PP&L DSM spending targets of $21 to $29 million in 1996. $29 to $44 million in 1997. $45 to $60 million in 1998. $61 to $76 million in 1999. and $77.00 to $92.00 in 2000 for a five year total of $233 to $300 million.

At these funding levels. PP&L's average DSM spending to retail revenues would be between 1.5% and 2.0%. which is comparable to the industry and MAAC averages of about 1.5% to 1.8% as projected by Hadley and Hirst through 1998. Additionally, these funding levels would bring PP&L's DSM spending to new construction expenditures percentages much closer to other utilities in the industry and in the PJM region. At these DSM spending levels. PP&L DSM expenditures as a percentage of new construction expenditures would equal 5.0-6.9% in 1996. 6.7-10.1% in 1997. 10.1-15.0% in 1996. 12.9-16.0% in 1999. and 17.2-20.5% in 2000.

Q: **HOW WOULD YOU ADDRESS THE DSM PROGRAM INEQUALITIES THAT EXIST WITHIN CUSTOMER CLASSES?**

A: I would limit load building programs a set percentage of PP&L's DSM portfolio. Allow, perhaps, 20% of DSM funding to go to load building or sales promotion DSM activities and allow PP&L to ramp up to this amount as it increases its total

DSM budget over the next five years. This would allow PP&L to maintain its core programs while developing new programs to address the current inequalities. The demand and energy conservation portion of its DSM portfolio, the remaining 80% percent, should mirror the customer make-up within the classes that are paying for the programs. For example, residential demand and energy conservation programs should be divided roughly 30% to electric heat customers and 70% baseload customers.

Q: **IS ASKING PP&L TO GO FROM A TOTAL DSM FUNDING LEVEL OF APPROXIMATELY 13.5 IN 1995 TO ONE BETWEEN $77 AND $99 MILLION BY THE TURN OF CENTURY WHILE PROVIDING FOR A MORE EQUITABLY DISTRIBUTION OF DIRECT DSM BENEFITS A REALISTIC GOAL CONSIDERING THE TIME IT TAKES TO DEVELOP AND IMPLEMENT NEW DSM PROGRAMS?**

A: I think so. PP&L would not have to develop its DSM portfolio on its own. There are a number of proven DSM technologies available in the market, and PP&L has an experience network of energy conservation providers in place in each of its five regions. These providers have been working in the energy conservation field for a number of years and they have the experience and expertise to help PP&L reach these targets.

PP&L could meet its DSM spending targets by tapping into this expertise. This would be accomplished through what would be a unique program in the industry--that is, Demand Side Management Program Development Grants. PP&L could divide the $9 to $16 million in incremental funding required in 1996 to meet its DSM funding target into a series of grants to be provided to existing energy conservation providers within PP&L's five regions. These grants would be used to develop new pilot DSM programs that target existing electric heat and baseload customers within PP&L's residential class, existing small commercial and industrial customers in PP&L's industrial and commercial class. Funding of these grants would continue at 1996 funding levels, adjusted for inflation, until such time as PP&L has met its DSM funding and program diversity targets as set by the PPUC. Incremental funding above PP&L's current projects needed to bring PP&L in line with DSM targets for years mentioned earlier would be used support full scale implementation of the most cost-effective pilot programs.

Q: **MR. KUENNEN, DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes.

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COMMISSION ON ECONOMIC OPPORTUNITY
EXHIBIT CRK 2
COMPARISON OF PP&L DSM RATIOS
TO INDUSTRY AVERAGE AND SELECTED PJM UTILITIES
DOCKET NO. R-00943271

RATIO	INDUSTRY[1]	PP&L[2]	PEPCO[3]	BG&E[4]	JCP&L[5]	PSE&G[6]
DSM TO RETAIL REVENUES	1.5%	0.4%	4.3%	3.1%	1.8%	1.4%
DSM TO NEW CONSTRUCTION	14.4%	2.5%	6.0%	18.3%	NA	4.0%
DSM TO PEAK DEMAND	6.8%	3.2%	6.5%	8.9%	NA	4.0%
DSM TO ENERGY SAVINGS	1.6%	0.06%	1.6%	0.6%	NA	0.1%

[1]Industry data for Retail Revenues, Peak Demand, and Energy Savings are for 1993 as reported in Hadley and Hirst, *Utility DSM Programs from 1989 Through 1998: Continuation or Cross Roads?*, Oak Ridge National Laboratory, February 1995. New Construction data are for 1991 as adapted from Pye and Nadel, *Rate Impacts of DSM Programs: Looking Past the Rhetoric*, American Council for an Energy-Efficient Economy, April 1994.

[2]PP&L's Ratios are based on estimated non-LIURP DSM expenditures $10.6 million for 1993. Retail Revenue and New Construction ratios were derived using data from PP&L's 1993 Annual Report. Peak Demand and Energy Savings ratios are based on data from the PPUC's July 1993 and August 1994 *Electric Power Outlook*.

[3]Potomac Electric Power Company data for Retail Revenues, Peak Demand, and Energy Savings are for 1993 as reported in Hadley and Hirst. New Construction data is for 1991 as adapted from Pye and Nadel.

[4]Baltimore Gas & Electric data for Retail Revenues, Peak Demand, and Energy Savings are for 1993 as reported in Hadley and Hirst. New Construction data was derived using 1993 DSM expenditure data from Hadley and Hirst and are for 1991 as adapted from Pye and Nadel and New Construction (electric) data from BG&E's *1994 Annual Report*.

[5]Jersey Central Power & Light Retail Revenue data is for 1993 and is derived from data supplied by New Jersey Bureau of Public Utilities and page F-75 of JCP&L's 1994 FORM 10-K.

[6]Public Service Electric & Gas data for Retail Revenues, Peak Demand, and Energy Savings are for 1993 as reported in Hadley and Hirst. New Construction data is for 1991 as adapted from Pye and Nadel.

OTS Statement No. 2 + Ex2
Witness: Joseph J. Sivulich
Dated: April 14, 1995 Srr 5-2-95 Hrs R-943271

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

Direct Testimony

of

Joseph J. Sivulich

Concerning:

Depreciation Expense
Net Negative Salvage Expense
Fossil Fueled Production Plant Decommissioning Expense
and
Nuclear Fueled Production Plant Decommissioning Expense

PENNSYLVANIA POWER & LIGHT COMPANY
Docket No. R-00943271

SUMMARY OF ADJUSTMENTS

I AM RECOMMENDING THAT THE FOLLOWING REDUCTIONS BE MADE TO PENNSYLVANIA POWER & LIGHT COMPANY'S OPERATING EXPENSE CLAIMS.

	DESCRIPTION	AMOUNT
1.	FOSSIL FUELED POWER PRODUCTION PLANT DECOMMISSIONING EXPENSE	$52,818,000
2.	NUCLEAR FUELED POWER PRODUCTION PLANT DECOMMISSIONING EXPENSE	$11,745,000
3.	FOSSIL FUELED POWER PRODUCTION PLANT DEPRECIATION EXPENSE (LIFE SPAN ADJ.)	$18,642,000
4.	SUSQUEHANNA SES POWER PRODUCTION PLANT DEPRECIATION EXPENSE (SINKING FUND ADJ.)	$30,400,000

IN ADDITION, I AM RECOMMENDING THAT THE COMPANY CONSIDER LENGTHENING THE LIFE SPANS OF ITS FOSSIL FUELED POWER PRODUCTION PLANTS IN FUTURE DEPRECIATION STUDIES FOR BOOK AND RATEMAKING PURPOSES.

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

A. My name is Joseph J. Sivulich. My business address is P.O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Valuation Engineer Supervisor. Currently, I am Supervisor of the Rate Structure/Engineering Section of the Energy Division. Prior to assuming that position, I was Supervisor of the Cost of Service Section of the Engineering and Rate Design Division of the Office of Trial Staff.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I am a 1970 graduate of King's College, Wilkes-Barre, Pennsylvania, where I earned a Bachelor of Science Degree in Mathematics. Since coming to the Commission in 1970, I have earned additional college credits in Engineering, Accounting and Business Law from the Harrisburg Area Community College. In addition, on December 8, 1979, I was awarded the Master of Engineering Degree from the Capitol Campus of

The Pennsylvania State University. My graduate studies have embraced the Industrial Engineering curriculum. Attached to this testimony as Appendix A is a statement which more fully describes my educational background and employment experience.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony in this proceeding is to address the impropriety of the Company's claims for fossil fueled production plant decommissioning expense, nuclear fueled production plant decommissioning expense, fossil fueled production plant depreciation expense, and nuclear fueled production plant depreciation expense.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I will address the Company's claims for fossil and nuclear fueled production plant decommissioning expense in Sections I and II, respectively. In addition, I will address the Company's claims for fossil fueled production plant depreciation expense in Section III and nuclear fueled production plant depreciation expense in Section IV. Section V is a summary of my recommendations.

Q. WHAT IS SHOWN IN OTS EXHIBIT NO. 2?

A. Schedule No. 1 is a copy of Attachment V-D-1a. This is the Company's calculation supporting its claim for $20,168,757 of net negative salvage expense under the Commission's established guidelines for the ratemaking treatment of net negative salvage on a current basis.

Schedule No. 2 is a copy of the company's response to OTS-RB-41. This schedule shows the Company's calculation supporting the $18.297 million of decommissioning expense related to the prospective retirement of nuclear fueled generating units that OTS recommends be adopted in these rate proceedings. The $18.297 million calculation excludes a contingency factor, rate of inflation factor, or an earnings on the trust factor. Schedule No. 3 is a copy of the company's response to OCA Set II, Q. 10, which shows the contingency amounts by category that were included in Mr. LaGuardia's nuclear decommissioning cost estimates.

Schedule 4 is a copy of the Company's response to OTS-RB-21-D, which shows the company's substantial additions to its power plants to keep them in compliance with the Clean Air Act.

Schedule 5 is a copy of the Company's response to OTS-RB-44, which shows that PP&L is pursuing several strategies that will keep all of its power plants in compliance with Clean Air Act requirements.

Schedule 6 is an OTS tabulation of the dollar amounts of contingency estimates included in Mr. LaGuardia's cost estimates for fossil fueled power production plants in PP&L Exhibit TSL-1. This schedule shows that $95.9 million of the Company's $677.4 million cost estimate is attributable to contingencies (extra costs that may be incurred under some unexpected occurrence) in his fossil fueled decommissioning estimates. Schedule 7 is a response to Office of Trial Staff on the record data request DR.OTS-1. This schedule provides PP&L's experienced net salvage by category (steam production, nuclear production, hydro production, other production, transmission, distribution, and general) for the period January 1990 through December 1994.

SECTION I - FOSSIL FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE

Q. WHAT IS DECOMMISSIONING EXPENSE?

A. Decommissioning expense is the cost incurred when taking a major electric generating unit or station out of service.

Q. WHAT IS NET NEGATIVE SALVAGE?

A. Net negative salvage occurs when the cost of removing utility plant and equipment from service exceeds the salvage value received for selling or reusing it. The Company defines cost of removal as the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and incidental handling. Salvage value is defined as the amount received for property retired, less expenses incurred in connection with the sale or in preparing property for sale; or, if retained, the amount at which the recoverable material is charged to materials and supplies, or the appropriate account. See OTS Cross Examination Exhibit No. 2, OTS-RB-19D.

Q. HOW DOES THE PENNSYLVANIA COMMISSION TREAT NET SALVAGE FOR RATEMAKING PURPOSES?

A. The Commission has traditionally allowed a utility to recover the net of positive salvage and cost of removal on a current basis for book and rate making purposes. The Commission uses a five year average of actually experienced net salvage as a leveling device. The accounting for experienced salvage and cost of removal is as prescribed by the Uniform System of Accounts. That is to say, they are normally booked in the year incurred. If something extraordinary occurs, they can be accumulated and amortized over some future period of time under the Extraordinary Property Loss provisions of the Uniform System of Accounts.

Q. DOES THE PENNSYLVANIA COMMISSION ALLOW A NUCLEAR POWER PLANT DECOMMISSIONING EXPENSE FOR RATEMAKING PURPOSES?

A. Yes. Nuclear power plants are the only exception to the Commission's established policy of handling net salvage on a current basis. In its orders allowing decommissioning expense for nuclear power plants, the Commission has stressed that it departed from its after the fact treatment because of the nuclear threat to health and safety and the need to have money available at the time of the retirement of radioactive plants in order to protect the public. The Commission has also required that the annuity and its accumulated interest be placed in an escrow fund and remain unavailable until the dismantling of the nuclear generating unit.

Q. WHAT IS FOSSIL FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE AS CLAIMED BY THE COMPANY IN THIS RATE PROCEEDING?

A. Fossil fueled production plant decommissioning expense of $52.818 million is defined as the present yearly expense of recovering the cost of retiring sixteen fossil fuel generating units at five different sites at various times in the future over the estimated remaining lives of those units. See PP&L Stmt. No. 13, p. 2. The Company is clearly asking for permission to depart from the Commission's traditional treatment of salvage by providing for prospective negative salvage of non-nuclear generation plant.

Company witness Mr. Bernini has testified that the cost estimate in current dollars for each unit was escalated at an annual rate of 4% to the scheduled retirement date. This determines the cost of decommissioning in the year retired which is the amount to be provided for through the annuity method. An annuity amount for each unit was determined assuming the fund would earn at the after tax rate of 5.5 percent. The annuities are based on site specific decommissioning cost estimates in 1994 dollars completed by TLG Services. See PP&L Stmt. No. 3, p. 22.

Q. HAVE YOU REVIEWED THE COMPANY TESTIMONY CONCERNING THE COMPANY'S CLAIM FOR DECOMMISSIONING EXPENSE?

A. Yes. I have reviewed the direct testimony and exhibits of Mr. Bernini concerning the Company's claims for net negative salvage and decommissioning expense. Statement No. 3, Exhibit Historic 1, Section D-11 and D-12, and Exhibit Future 1, Section D-11 and D-12. I have also reviewed the testimony and exhibits of Mr. Hoch concerning the Company's traditional claims for experienced net negative salvage. Specifically, these documents are Statement No. 4 and several Company exhibits including but not limited to Exhibit Historic 1, Section D-17 and Exhibit Future 1, D-17.

I have also reviewed the testimony and exhibits of Mr. LaGuardia concerning his estimates of decommissioning expense, which were identified as Statement No. 13 and Exhibits TSL-1 (Fossil) and TSL-2 (Nuclear), respectively.

In addition, I have reviewed the testimony of Mr. Hill concerning decommissioning expense which was included as a part of his Statement No. 1.

Q. WHAT DID YOUR REVIEW OF MR. LAGUARDIA'S TESTIMONY AND EXHIBITS REVEAL?

A. Mr. LaGuardia was contracted by the Company to estimate the cost of dismantling sixteen of its generating units at five different locations. Mr. LaGuardia assumed that all of these generating units would be retired using 1994 technology. Mr. LaGuardia also studied two large jointly owned nuclear generating units at Susquehanna Steam Electric Station using 1993 technology. PP&L has several other generating units that were not part of Mr. LaGuardia's study. See PP&L Exhibit No. DAK 4.

Q. WHAT DID YOUR REVIEW OF MR. BERNINI'S TESTIMONY AND EXHIBITS REVEAL?

A. Mr. Bernini used Mr. LaGuardia's estimates of the cost of dismantling the fossil fuel and nuclear generating units at the end of 1994 and 1993, respectively. He then estimated the annual charge that would be necessary to write off the cost estimate over the remaining lives of the units while allowing for a 5.5 percent after tax return on the annual sinking fund and inflating the cost estimate by 4.0 percent per year.

Q. WHAT DID YOUR REVIEW OF MR. HOCH'S TESTIMONY AND EXHIBITS REVEAL?

A. Mr. Hoch is the witness responsible for supporting the company's claimed experienced net negative salvage. PP&L is claiming $20,168,757 of net negative salvage based upon a five year average of the net of experienced cost of removal and experienced salvage. The historical support for this claim is provided in the company's response to OTS-RB-19D, which is included in OTS Cross Examination Exhibit No. 2. A review of Attachment V-D-1a, page 11 of 14 (included as Schedule 1 in OTS Exhibit No. 2 for convenience) shows that over $7.7 million of this annual expense claim is for fossil fueled production plant and $4.4 million for nuclear fueled production plant. The data in Schedule 7 of OTS Exhibit No. 2 further demonstrates that net salvage is currently being experienced and provided for on a monthly basis for all categories of plant including fossil fueled production plant (Steam Production).

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE CLAIMED $20,168,757 OF ANNUAL NET SALVAGE EXPENSE?

A. I recommend that the $20,168,757 be allowed for ratemaking and book purposes. I would like to point out that this is the appropriate vehicle for recovering the cost of decommissioning fossil fueled power production units after each unit has been retired in the future.

Q. WHAT DID YOUR REVIEW OF THE COMPANY'S FOSSIL FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE CLAIM INDICATE?

A. The Company has inflated its operating expense claim, for the future test year ended September 30, 1995, related to future decommissioning of plant that is still in service, by $52.818 million. PP&L Exhibit Future 1, Section D-12, p. 1. My review indicates that the claim is related to routine future retirement projects. Some of these projects are admitted to be many years in the future. None of the claimed decommissioning expense is related to retirement work in progress at September 30, 1995. In fact, the retirement of some of these units could be further postponed if the units are upgraded and their useful lives extended. Also, the retirement dates can slip, if their capacity is needed to ensure service reliability. As discussed later in my testimony, some of the life spans and resultant remaining lives that the Company used for the calculation of its depreciation expense and fossil fueled power production plant decommissioning expense claims were erroneously shortened. In fact, OTS is of the opinion that the life spans of the Martins Creek Unit 1 and Unit 2, Sunbury SES, and Holtwood SES should have been lengthened instead of shortened. PP&L has repeatedly admitted that it has no plans to retire any generating unit for the next twenty years, which emphatically indicates that the life spans of these power plants should have been lengthened. Tr. 110.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Administrative Law Judge and the Commission reject the Company's proposed $52.818 million annual decommissioning expense for fossil fueled power production plants.

Q. WHY ARE YOU RECOMMENDING THE REJECTION OF THE CLAIMED DECOMMISSIONING EXPENSE?

A. The following factors support my recommendation that PP&L's decommissioning expense claim be rejected:

(1) The Company is making a blatant claim for prospective net negative salvage, which my counsel informs me, has been disallowed by this Commission since the Penn Sheraton decision in 1962. See Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 198 Pa. Superior Ct. 618, 184 A.2d 324 (1962.) This decision prohibited the Commission from charging current ratepayers for the prospective removal of steam mains in the City of Pittsburgh. Since 1970, the Commission has

evolved a plan to handle all net salvage on a current basis for all utilities with the noted exception of nuclear plant decommissioning expense.

(2) The Company's claim does not meet the criteria for inclusion in the only notable exception to the Commission's ban on prospective net negative salvage. That is to say, this claim does not meet the overriding need to protect the public from a very real radioactive danger as in the Decommissioning of Nuclear Power Plants.

(3) The calculations and assumptions underlying the Company's claimed decommissioning expense are speculative.

(4) The Company will recover prudently incurred net negative salvage expense on eligible plant and equipment after they have been retired.

Q. CAN YOU ELABORATE ON WHAT YOU MEAN WHEN YOU STATE THAT THE CALCULATIONS AND ASSUMPTIONS UNDERLYING THE COMPANY'S CLAIMED DECOMMISSIONING EXPENSE ARE SPECULATIVE?

A. Yes. The Fossil Fueled Power Production Plant Decommissioning cost estimate is based on at least 49 major assumptions (PP&L Exhibit TSL-1, pages 3-7) while the Nuclear Fueled Power Production Plant

Decommissioning cost estimate employs 23 major assumptions (PP&L Exhibit TSL-2, pages 4-12). A change in any one of these major assumptions could result in a significantly lower cost estimate.

Mr. LaGuardia has included $95.9 million and $127.4 million in contingencies (extra costs that may be incurred under some unexpected occurrence) in his fossil fueled and nuclear fueled decommissioning estimates, respectively. OTS Exhibit No. 2, Schedule 6 provides a tabulation of the contingency dollar amounts included in the Company's cost estimate and decommissioning expense claim for fossil fueled power production plants. The Commission has recognized that contingencies are speculative and has rejected them in nuclear production plant decommissioning allowances.

Moreover, the Company's decommissioning expense calculations utilize life estimates that are clearly too short for Martins Creek, Sunbury, and Holtwood fossil fueled power production plants. In addition, based on the Company's repeated assertions that it does not plan to retire any generating plants in the next 20 years, the retirement date of 2010 utilized by the Company in its decommissioning expense calculations for Martins Creek Units 3 & 4 appears to be in error by at least six years. See PP&L Exhibit No. DAK 4 and Tr. 110.

Q. ARE YOU AWARE OF THE COMMISSION'S RATEMAKING TREATMENT OF NET NEGATIVE SALVAGE?

A. Yes. I have reviewed the claimed decommissioning expense in light of this Commission's established procedure as set forth in many Commission orders and I am convinced that the claimed decommissioning expense **does not meet** the criteria for inclusion in net negative salvage expense. That is to say, the claim is based on prospective events in the very distant future. To be allowable, a claim for net negative salvage must be based on actually incurred retirements, cost of removal, and salvage.

Q. WHAT ARE THE CHARACTERISTICS OF THE COMPANY'S FOSSIL FUELED POWER PRODUCTION PLANT DECOMMISSIONING EXPENSE CLAIM THAT SUPPORT YOUR RECOMMENDATION?

A. Retirement of these units are admitted to be many years in the future. Unlike nuclear units, there are no governmental regulations requiring the retirement of these units. Also, none of the projects can be construed to be significant, relevant, and substantial when compared to normal levels of net negative salvage. The actual retirement of the fossil fueled generating units will occur over many years and as a result will not place a large burden on the Company in any one year. It also should be remembered that the actual dismantling of each unit could take nearly three years. PP&L Exhibit No. TSL-1, Page 1 of 5 shows that Mr. LaGuardia's estimated duration of dismantling activities range from 20.18 months for Holtwood to 34.97 months for Brunner Island. On page 4-7 of the May, 1994 Pennsylvania Power & Light Company "Resource Planning Report", the Company states that "[b]ecause current studies indicate continued operation of its fossil and hydro units are cost-effective, PP&L does not anticipate any major generating unit retirements during the 20 year planning period." A copy of page 4-7 of the May, 1994 Resource Planning Report can be found in OTS Cross Examination Exhibit No. 2.

Q. DO YOU HAVE ANY CONCERN FOR FUTURE RATEPAYERS HAVING TO PAY FOR THE REMOVAL OF PLANT FROM WHICH THEY WILL RECEIVE NO SERVICE?

A. No. This concern is misplaced since most power plants are placed in service and retired at different points in time. Present customers will also be future customers when some of the studied power plants are retired. The removal of power plants and their associated equipment is an ongoing activity. Present customers are certainly paying for the removal of some plant that served previous generations of ratepayers. In my opinion, the recovery of net salvage after retirement is the fairest method to apply these costs to all generations of ratepayers.

Q. IN YOUR OPINION, IS THERE ANYTHING UNIQUE ABOUT THE COMPANY'S CLAIM THAT WOULD JUSTIFY AN EXCEPTION SIMILAR TO THE COMMISSION'S TREATMENT OF NUCLEAR PLANT DECOMMISSIONING EXPENSE?

A. No. Company witness Mr. LaGuardia has testified that the studied fossil fueled power plant units do not have any extraordinary safety problems. Tr. 963-964. Since conventional generating plants do not present any compelling safety related issues requiring the outlay of money for decommissioning prior to retirement, I recommend that the net salvage associated with the retirement of these units be handled as a current expense item after actual retirement.

Q. **IN YOUR OPINION, IS THERE ANYTHING UNIQUE ABOUT THE COMPANY THAT WOULD JUSTIFY MODIFICATION OF THE TRADITIONAL NET NEGATIVE SALVAGE METHODOLOGY TO INCLUDE PROSPECTIVE RETIREMENT OF CONVENTIONAL POWER PLANTS?**

A. No. I believe that the traditional treatment of net negative salvage on a current basis for plant and equipment that are actually retired should continue. This separation of current and future negative salvage is necessary to ensure that customers are not being asked to pay the net expense of retiring plant and equipment before these costs are actually incurred, many years into the future.

The principle of expensing net negative salvage on a current basis should not be ignored to reach out for additional net negative salvage expense (decommissioning expense) prior to that plant and equipment going out of service. A Company should not be allowed to reach out beyond the end of the future test year to pick up extra net negative salvage expense related to routine future retirement projects.

Q. IN YOUR OPINION, WILL DISALLOWANCE OF THE COMPANY'S FOSSIL FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE CLAIM PREVENT IT FROM RECOVERING ITS LEGITIMATE NET NEGATIVE SALVAGE EXPENSE AFTER THE FUTURE RETIREMENT OF GENERATING PLANT AND EQUIPMENT?

A. No. The present disallowance of the Company's claim, which is based on a future event, will not prevent it from recovering the full amount of decommissioning expense (net negative salvage) when it becomes an actual expense. The Company will be given the opportunity to claim decommissioning expense as part of some future rate proceeding. At that point in time, it will be a current expense rather than a prospective expense.

SECTION II - NUCLEAR FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE

Q. PLEASE DESCRIBE THE NUCLEAR FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE AS CLAIMED BY THE COMPANY IN THIS RATE PROCEEDING.

A. Nuclear fueled production plant decommissioning expense is defined as the present yearly expense of recovering the cost of retiring two nuclear fueled generating units at the Susquehanna Steam Electric Generating Station in the future over the estimated remaining lives of those units. The Company is again asking the Commission for permission to provide for prospective negative salvage. The Company has inflated its operating expense claim for the future test year ended September 30, 1995, related to future decommissioning of nuclear fueled production plant that is still in service, by $11.7 million. My review indicates that the claim is overstated because it includes $122.8 million in contingency estimates and is inflated by 4 percent per year between 1993 and the estimated retirement dates of Unit 1 and Unit 2, respectively. According to Mr. LaGuardia, the $122.8 million of contingencies represents 18 percent of the total cost estimate in 1993 dollars. Tr. 1063.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM FOR NUCLEAR FUELED PRODUCTION PLANT DECOMMISSIONING EXPENSE?

A. The Company's current request for nuclear fueled production plant decommissioning expense is based on a site specific study performed by Mr. LaGuardia. The estimated cost of immediate dismantlement of both the radiological and non-radiological portions of the nuclear fueled

Susquehanna Steam Electric Station's (SSES) two generating units is $804.3 million in 1993 dollars. Allegheny Electric Cooperative, Inc. owns 10 percent of SSES; therefore, only 90 percent of the total cost estimate or $724 million is applicable to PP&L. Unit 1 has an operating license which expires in the year 2022 while Unit 2 has an operating license which expires in the year 2024.

PP&L's share of the decommissioning cost of $315.5 million for Unit 1 and $408.4 million for Unit 2 in 1993 dollars was escalated at a rate of 4 percent to estimate the cost of decommissioning in the years 2022 and 2024, respectively. The projected value of the decommissioning trust in 2022 for Unit 1 and 2024 for Unit 2 was determined assuming the trust realizes a 5.5 percent annual after-tax rate of return. The value of the trust was then deducted from the estimated cost of decommissioning to determine the net amount of additional decommissioning funds which must be provided for through the annuity method. This resulted in the claimed annual cost for decommissioning of $12.6 million for Unit 1 and $17.4 for Unit 2. See PP&L Stmt. No. 3, p. 20.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Administrative Law Judge and the Commission reject the Company's proposed $22.9 million increase in annual decommissioning expense for nuclear fueled power production plants. In place thereof, I recommend that the Commission allow $11.2 million for increased nuclear fueled power production plant decommissioning expense. In short, I recommend an allowance of $18,297,000 for Nuclear Decommissioning Expense instead of the $30,042,000 claimed by the Company. This results in an OTS adjustment of $11,745,000. See the Company's response to OTS-RB-41, which has been included in OTS Exhibit No. 2 as Schedule 2. This allowance is based on Mr. LaGuardia's 1993 cost estimate <u>without</u> the $122.8 million in contingencies, the inflation factor cost estimate of 4 percent per year, and the trust fund estimated after-tax 5.5 percent per year growth. The details of the contingency included in Mr. LaGuardia's cost estimates are provided in the Company's response to OTS-RB-39, which has been included in OTS Cross Examination Exhibit No. 17. Also, see Schedule 3 of OTS Exhibit No. 2 for a breakdown of the contingency percentages by estimation category.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. My recommendation is based on the methodology employed by the Pennsylvania Commission in providing for Nuclear Decommissioning expense in past PP&L rate cases. For example, in PP&L's 1984 rate case, the Commission allowance for nuclear decommissioning expense was calculated on the current best estimate of decommissioning cost **without any contingencies and without any reflection of inflation factor or growth factor for the decommissioning fund**. The prior orders make it clear that the Commission is willing to consider periodic increases to the level of funding based upon new cost estimates but is unwilling to accept increases in the cost estimates based upon contingencies or inflation. It can be inferred from these orders that the non recognition of the future increase resulting from the trust fund earnings will offset some of the increases in cost due to inflation. In addition, Mr. G. T. Jones has stated that "PP&L will review the Susquehanna Decommissioning Cost Estimate at two-year intervals, or more frequently, if there are material changes to the applicable estimation information, to assure that the estimate is kept current throughout the life of the plant." See OCA Cross Examination Exh. No. 15, Sch. II, Q. 2.

SECTION III - FOSSIL FUELED PRODUCTION PLANT DEPRECIATION EXPENSE

Q. HOW DOES THE COMPANY PROVIDE FOR THE DEPRECIATION OF FOSSIL FUELED PRODUCTION PLANT?

A. The Company states that the actuarial techniques used in the current depreciation study are the same as those employed in a prior service life study completed in 1981, which was accepted by the Commission in its final order at Docket No. R-842651. The calculation of the annual depreciation accruals reflects the application of the service life parameters from the service life study and the straight line remaining life method of depreciation. The interim survivor curves used as a parameter of the life spanning depreciation procedure for power production facilities in Steam Production, Nuclear Production, Hydro Production and Other Production are based on an interim retirement study completed in 1993. In this filing, the deactivation dates and resulting life spans used for the life spanning calculations have been reduced for the Martins Creek Units 1 and 2, Sunbury Steam Electric Station (SES) and Holtwood SES, and extended for Conemaugh SES and Keystone SES. See PP&L Stmt. No. 3, p. 6.

Q. WILL YOU PLEASE ELABORATE ON HOW THE COMPANY SHORTENED THE LIFE SPANS OF MARTINS CREEK UNIT 1 AND UNIT 2, SUNBURY SES, AND HOLTWOOD SES?

A. Yes. PP&L's depreciation expert disavowed any responsibility for the shortening of the life spans of the Martins Creek Unit 1 and Unit 2, Sunbury SES, and Holtwood SES. He indicated that Mr. Krall was responsible for recommending the shortening of the respective life spans. Mr. Krall has testified that the life spans were shortened because of possible changes in air pollution requirements. See PP&L Stmt. No. 5, p. 10. A review of PP&L Exhibit DAK 4, indicates that the life span is derived from the deactivation date estimate. Mr. Krall "revised" the deactivation dates for Martins Creek 1&2 from the year 2015 to 2003. He "revised" the deactivation date of Sunbury 1, 2, 3 & 4 from the year 2010 to 2003. He also "revised" the deactivation date of Holtwood 17 from the year 2009 to 2003. See PP&L Exhibit No. DAK 4.

Q. DO YOU AGREE WITH THE COMPANY'S DEPRECIATION CLAIMS FOR FOSSIL FUELED POWER PRODUCTION PLANTS?

A. No. I agree with the Company's extending of the estimated life spans for Conemaugh SES and Keystone SES. The extending of the life spans at

Conemaugh SES and Keystone SES is reasonable and reflects management plans for these units. In fact, the longer life spans for these two plants reflects an industry trend of maintaining, upgrading, and extending the life spans of fossil fueled power plants as a less costly option to building new power production units. However, I vigorously disagree with the reduction in life spans for Martins Creek Units 1 and 2, Sunbury SES, and Holtwood SES.

Q. WOULD YOU PLEASE EXPLAIN YOUR REASONS FOR DISAGREEING WITH THE COMPANY'S SHORTER LIFE SPAN ESTIMATES FOR MARTINS CREEK UNITS 1 AND 2, SUNBURY SES AND HOLTWOOD SES?

A. Yes. A review of the record in these proceedings will clearly show that the shorter life spans are not justified in this rate case because:

1. They are only utilized for this rate case to generate a higher revenue requirement.
2. There are no management plans to retire these units early.
3. There are no management plans to retire any power production unit in the next twenty years. Page 4-7 of the May, 1994 Pennsylvania Power & Light Company Resource Planning Report indicates that

the company has no plans to retire any major generating unit in the 20 year planning period. <u>See</u> OTS Cross Examination Exhibit No. 2.

4. The company is adding sizeable capital additions to each of these units to continue their existence as long as economically possible. See Schedule 4 of OTS Exhibit No. 2.

5. There are no government mandates that would force these units to be retired early.

6. Air pollution regulations are currently being met by PP&L. <u>See</u> Schedule No. 5 of OTS Exhibit No. 2.

7. PP&L is maintaining all of its generating units to ensure maximum life spans.

Q. DOES THE RECORD IN THESE PROCEEDINGS SUPPORT THE REVISED DEACTIVATION DATES AND SHORTENED LIFE SPANS FOR MARTINS CREEK UNIT 1 AND UNIT 2, SUNBURY SES, AND HOLTWOOD SES?

A. No. The record is replete with admissions that PP&L has no plans to retire any generating unit in the next 20 years. Tr. 110. In addition, Mr. Krall stated that "[a] decision was made to reflect the possibility that they would be retired earlier in the depreciation schedule. . . Again, we're using the term "retirement date," and I don't want to leave the impression that we have a current plan to retire those plants on 2003." Tr. 188. Moreover, Mr. Hoch admitted that reducing the life spans of these stations would produce a higher revenue requirement for PP&L than if the original life spans were continued. Tr. 111.

Q. **CAN YOU QUANTIFY THE EFFECT THAT THE COMPANY'S ERRONEOUS SHORTENING OF THE LIFE SPANS OF THE MARTINS CREEK UNIT 1 AND UNIT 2, SUNBURY SES, AND HOLTWOOD SES HAS HAD ON FOSSIL FUELED POWER PRODUCTION PLANT DEPRECIATION EXPENSE?**

A. Yes. The effect can be seen by referring to the Company's response to OTS-RB-43 and comparing the total depreciation expense on Attachment 1, which utilizes the longer life spans from the 1989 Depreciation Study, with the amount of the claim for the future test year ended September 30, 1995 shown on page 1 of 14 of V-D-1a. Mr. Hoch admitted that the increase in depreciation expense due to shortened life spans is approximately $18,641,711. Tr. 113.

Q. WHAT ~~IS~~ ARE YOUR RECOMMENDATIONS CONCERNING THE USE OF THE COMPANY'S SHORTENED LIFE SPANS FOR DEPRECIATION PURPOSES IN THESE PROCEEDINGS?

A. I recommend that the shortened life spans be rejected and that depreciation expense be based on the longer services lives that were in effect prior to the filing of this rate case. Concurrently, I recommend that the Company's annual depreciation expense claim be reduced by $18,641,711 for fossil fueled power production plant. In addition, consistent with PP&L's plans to not retire any generating units in the next 20 years, I recommend that the Company consider lengthening the life spans of its fossil fueled power production plants in future depreciation studies for book and ratemaking purposes. It is likely that the 1989 Depreciation Study overstates total depreciation expense for these plants. However I have not proposed to reduce depreciation expense to reflect an expansion of life spans.

SECTION IV - NUCLEAR FUELED PRODUCTION PLANT DEPRECIATION EXPENSE

Q. HOW DOES THE COMPANY PROVIDE FOR THE DEPRECIATION OF NUCLEAR FUELED PRODUCTION PLANT?

A. The Company states that property installed at the Susquehanna SES prior to January 1, 1989 is depreciated using a system of depreciation known as modified sinking fund (MSF). This method was approved by the Commission in its final order at Docket No. R-842651 and subsequently modified by the Commission at Docket No. P-880332 to permit the Company to comply with the requirements of Statement of Financial Accounting Standards No. 92. Annual depreciation expense for property covered by this agreement is comprised of annual depreciation calculated by the MSF and the annual amortization amount of $19.7 Million related to the P-880332 order. Under terms of the agreement, the depreciation expense increases each year through 1998 and will revert to straight line remaining life depreciation on January 1, 1999. For example, the total depreciation expense for 1994 is $127,916,725 and for 1995 is $141,316,228. (PP&L Statement No. 4, p. 12). Plant installed after December 31, 1988 is depreciated using the straight line method with the average life span procedure and remaining life technique.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE MODIFIED SINKING FUND THAT IS CURRENTLY BEING UTILIZED FOR THE SUSQUEHANNA UNITS?

A. Yes. The modified sinking fund method was constructed by the Company and accepted by this Commission as a means of deferring some of the large revenue requirement increases that came about with the in service dates of Susquehanna Unit 1 and Unit 2, respectively. "The primary reason for proposing this methodology was to minimize the impact on customers' rates associated with placing Unit 1 in service. This methodology was also proposed and approved for Susquehanna SE Unit 2 at Docket No. R-842651." PP&L Stmt. No. 4, p. 10. The MSF will terminate at the end of 1998 and revert to normal straight line remaining life depreciation.

Q. HAS THE COMPANY MADE A NEW PROPOSAL CONCERNING THE DEPRECIATION METHOD TO BE APPLIED TO PRE-1989 NUCLEAR PRODUCTION PLANT?

A. Yes. The Company is proposing a revision that will result in a higher level of depreciation expense for this rate case. "The Company is proposing to include in customers' rates a levelized amount of depreciation in place of the annually increasing amount. This levelized amount would remain in effect until January 1, 1999, at which time the depreciation expense amount would decrease to the straight-line level and the amortization, approved by the Commission in 1988, would terminate." PP&L Stmt. No. 4, pp. 12-13.

Q. CAN YOU QUANTIFY THE AMOUNT OF INCREASED DEPRECIATION EXPENSE THAT WILL RESULT FROM THE COMPANY'S LEVELIZING SCHEME?

A. Yes. Included in OTS Cross Examination Exhibit No. 2 is a response to OCA Set II Q. 4 which indicates that the effect of the Company's levelizing proposal is to increase the test year Susquehanna depreciation expense by $30,388,074.

Levelized Susquehanna depreciation expense	$172,729,583
Present modified sinking fund depreciation	<u>142,341,509</u>
Difference	$30,388,074

Q. DO YOU AGREE WITH THE COMPANY PROPOSED $30.4 MILLION INCREASE IN SUSQUEHANNA SES DEPRECIATION EXPENSE?

A. No. I do not agree with this latest proposal for several reasons:

1. It increases the Company's current revenue requirement by $30.4 million with no apparent benefit to PP&L's customers.

2. Unlike the 1988 petition, this proposed change is not mandated by the Financial Accounting Standards Board.

3. Allowing the MSF agreement to run its normal course will result in a lower revenue requirement for PP&L's customers in the present case.

4. Continuing the present MSF until 1999 will not prevent the company from recovering all of the depreciation expense that it is entitled to.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S REQUESTED $30.4 MILLION INCREASE IN THE SUSQUEHANNA SES DEPRECIATION EXPENSE?

A. I recommend that the entire $30.4 million increase in depreciation expense for Susquehanna SES be rejected.

SECTION V - SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. MR. SIVULICH, WOULD YOU PLEASE SUPPLY A BRIEF SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS?

A. Yes. In Section I, I have recommended approval of the Company's experienced net negative salvage claim of $20,168,757 and rejection of its

$52.818 million claim for annual decommissioning expense for fossil fueled power production plants. In Section II, I have recommended that a company allowance of $18,297,000 for annual decommissioning expense for nuclear fueled power production plants be adopted instead of the $30,042,000 claimed by the Company. In Section III, I have recommended that the Commission reject the use of the shortened life spans that are not consistent with management plans to operate all of its generating plants for at least 20 more years. Based on the currently in place longer life spans for Martins Creek, Sunbury, and Holtwood generating plants, I have recommended a $18,641,711 decrease in the Company's claim for annual depreciation expense related to fossil fueled power production plant. Also, I have recommended that the Company consider lengthening the life spans of its fossil fueled power production plants in future depreciation studies for book and ratemaking purposes. Finally, in Section IV, I have recommended that the entire $30.4 million increase in depreciation expense for Susquehanna SES be rejected. The Company's proposal merely increases the current rate case's revenue requirement without any apparent need or any apparent benefit for its customers.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

Appendix A

Professional and Educational Experience of
Joseph J. Sivulich

Education:

B.S. Mathematics, King's College, 1970.

Master of Engineering, The Pennsylvania State University at the Capitol Campus, 1979.

Earned additional credits in accounting, business law, and engineering at the Harrisburg Area Community College, 1970-1978.

Experience:

March 1994 to date: Supervisor of Rate Structure/Engineering Section, Energy Division, Office of Trial Staff. Supervise staff of engineers in the review and prosecution of gas and electric rate filings in the areas of valuation, depreciation, cost of service, rate structure, 1307 (f) gas cost, and tariff propriety. Participate in rate case proceedings as an expert witness in all areas of Valuation Engineering and Rate Structure areas.

December 1987 to March 1994: Supervisor of Cost of Service Section, Engineering and Rate Design Division, Office of Trial Staff. Supervise staff of engineers in the review and prosecution of gas, electric, telecommunications, and water rate filings in the areas of cost of service, rate structure, and tariff propriety. Participate in rate case proceedings as an expert witness in the areas of cost of service and rate structure.

September 1986 to December 1987: Supervisor of Engineering Section, Rate Design Division, Office of Trial Staff, Pennsylvania Public Utility Commission. Supervise staff of engineers in the review and prosecution of gas, electric, telecommunications, and water rate filings in the areas of cost of service, rate structure, and tariff propriety. Participate in major rate case proceedings as an expert witness in the areas of cost of service and rate structure.

April 1981 to September 1986: Supervisor of Valuation Section, Gas Division, Bureau of Rates, Pennsylvania Public Utility Commission. Supervise staff of engineers in the areas of valuation, depreciation, rate structure, and cost of service. Participate in major rate case proceedings as an expert witness in the areas of valuation and depreciation.

January 1978 to April 1981: Supervisor of Valuation Section, Communications Division, Bureau of Rates, Pennsylvania Public Utility Commission. Supervise staff of engineers in the review and prosecution of communications rate filings in the areas of valuation, depreciation, rate structure, and cost of service. Participate in major rate case proceedings as an expert witness in the areas of valuation and depreciation.

April 1975 to January 1978: Public Utility Engineer III, Engineering and Economics Division and then Communications Division, Bureau of Rates and Research, Pennsylvania Public Utility Commission. Participated in major rate case proceedings as a technical expert and adviser in the areas of valuation and depreciation. Testified as an expert witness in a major electric rate proceeding. Acting Supervisor of several engineers involved in the review and prosecution of major rate cases in the areas of valuation and depreciation. Prepared valuation and depreciation portion of orders and reports for the Commission's consideration.

December 1972 to April 1975: Public Utility Engineer II. Valuation Engineering Division, Bureau of Rates and Research, Pennsylvania Public Utility Commission. Participated in major rate case proceedings as a technical expert and adviser. Prepared valuation and depreciation portion of orders and reports for Commission consideration.

August 1971 to December 1972: Public Utility Engineer I, Engineering Section, Bureau of Rates and Research, Pennsylvania Public Utility Commission. Participated in major rate case proceedings as a technical expert. Prepared valuation and depreciation portion of orders and reports for Commission consideration.

June 1970 to August 1971: Government Career Trainee, Valuation Engineering Section, Bureau of Rates and Research, Pennsylvania Public Utility Commission. Assisted in the prosecution of major rate case proceedings. Performed research and studies in the areas of valuation and depreciation. Assisted in the preparation of the valuation and depreciation portion of orders and reports for Commission consideration.

Professional Affiliation:

Member of the Engineers Society of Pennsylvania.

Research:

Statistical Analysis of Life Spans of Electric Generating Power Production Units in Pennsylvania, Master's Paper, The Pennsylvania State University at the Capitol Campus, September, 1979.

Special Projects:

Principal depreciation expert on the Tri-Annual Bell Telephone of Pennsylvania Represcription of Depreciation Rates before the Federal Communications Commission in 1979, 1982, and 1985.

Chairman of the Bureau of Rates Depreciation Committee charged with overseeing the transition from a calculated depreciation reserve to a book depreciation reserve for ratemaking purposes. Authored the first draft and participated in the finalization of the Depreciation Committee's Guidelines".

Training:

Michigan Technological University; Depreciation Training Programs in July, 1971 and July, 1972.

Michigan State University; Annual Regulatory Studies Program in July, 1974.

Western Michigan University; Negative Salvage seminar in November, 1976 conducted by the Center for Depreciation Studies.

The Pennsylvania State University; Continuing Education Course on the Physical Functioning of Public Utility Equipment from November, 1976 through January, 1977.

Western Michigan University; Advanced Depreciation Practice seminar in July, 1978 conducted by the Center for Depreciation Studies.

Appearances as Expert Witness:

Metropolitan Edison Company rate case at R.I.D. 434 on December 28, 1977.

Mid-Penn Telephone Corporation rate case at R-77090462 on March 22, 1978.

Commonwealth Telephone Company rate case at R-77090482 on April 13, 1978.

The Bell Telephone Company of Pennsylvania rate case at R-78120719 on February 28, 1979.

The Bell Telephone Company of Pennsylvania rate case at R-80061235 on December 19, 1980.

T. W. Phillips Gas & Oil Co. rate case at R-811615 on January 6, 1982.

Philadelphia Electric Company - Gas Operations rate case at R-811719 on February 17, 1982.

U.G.I. Corporation - Gas Utility Division rate case at R-821899 on August 4, 1982.

Columbia Gas of Pennsylvania, Inc. rate case at R-822042.

Equitable Gas Company rate case at R-822133 on March 8, 1983.

National Fuel Gas Distribution Corporation rate case at R-822145 on March 17, 1983.

U.G.I. Corporation - Gas Utility Division rate case at R-832331 on December 21, 1983.

Philadelphia Electric Company - Gas Operations rate case at R-832410 on December 21, 1983.

Columbia Gas of Pennsylvania, Inc. rate case at R-832493 on April 13, 1984.

Apollo Gas Company rate case at R-842572 on June 5, 1984.

Equitable Gas Company rate case at R-842769 on May 29, 1985.

National Fuel Gas Distribution Corporation rate case at R-850287 on July 14 and August 8, 1986.

North Penn Gas Company rate case at R-860535 on June 26, 1987.

Columbia Gas of Pennsylvania rate case at R-870832.

Philadelphia Suburban Water Company rate case at R-870840 on February 6, 1988.

Equitable Gas Energy Company rate case at R-880941 on June 30, 1988.

Equitable Gas Company rate case at R-880971 on August 10, 1988.

The Peoples Natural Gas Company rate case at R-880961 on September 19, 1988.

Equitable Gas Company 1307(f) proceeding at R-891238 on May 24, 1989.

Columbia Gas of Pennsylvania, Inc. rate case at R-891468 on May 9, 1990.

Equitable Gas Company rate case at R-901595 on July 18, 1990.

Pennsylvania Gas and Water Company rate case at R-901726 on November 1, 1990 and December 4, 1990.

U.G.I. Corporation - Gas Utility Division 1307(f) proceeding at R-911973 on August 7, 1991.

Pennsylvania Gas and Water Company rate case at R-922482 on January 28, 1993.

Mechanicsburg Water Company rate case at R-922502 on March 16, 1993.

Equitable Gas Company transportation rate investigation at I-900009 on March 16, 1993.

Pennsylvania Gas and Water Company - Springbrook rate case at R-932667 on August 20, 1993.

Roaring Creek Water Company rate investigation at R-932665 on September 27, 1993.

The Peoples Natural Gas Company rate case at R-932866 on March 17, 1994.

West Penn Power Company rate case at R-942986 on August 2, 1994.

OTS Exhibit No. 2
Witness: Joseph J. Sivulich
Dated: April 14, 1995

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

Exhibit to Accompany

the

Direct Testimony

of

Joseph J. Sivulich

Concerning:

Depreciation Expense
Net Negative Salvage Expense
Fossil Fueled Production Plant Decommissioning Expense
and
Nuclear Fueled Production Plant Decommissioning Expense

Pennsylvania Power & Light Company

		Original Cost 9/30/95	Claimed Depreciation Reserve 9/30/95	Annual Depreciation Accrual
Net Salvage				
	Steam Production		(16,947,774)	7,739,310
	Nuclear Production		(16,658,679)	4,413,319
	Hydro Production		(809,502)	63,443
	Other Production		(92,723)	5,996
	Transmission		(631,175)	(3,058)
	Distribution		(18,078,496)	7,928,984
	General Plant		(549,102)	20,761
	Total -- Net Salvage		(53,767,451)	20,168,757
Steam Production -- Leasehold Improvements				
	Sunbury SES			
311.0	Structures and Improvements	49,346	49,346	Amortize to O&M acct
	Subtotal -- Sunbury SES	49,346	49,346	0
	Martins Creek #1 & #2 SES			
312.0	Boiler Plant Equipment	79,141	81,731	Amortize to O&M acct
316.0	Misc Power Plant Equipment	6,427	6,837	Amortize to O&M acct
	Subtotal -- Martins Creek #1 & #2 SES	85,568	88,568	0
	Martins Creek #3 & #4 SES			
311.0	Structures and Improvements	277,620	172,531	Amortize to O&M acct
312.0	Boiler Plant Equipment	1,473,260	870,070	Amortize to O&M acct
315.0	Accessory Electric Equipment	24,991	13,452	Amortize to O&M acct
316.0	Misc Power Plant Equipment	5,039	3,916	Amortize to O&M acct
	Subtotal -- Martins Creek #3 & #4 SES	1,780,910	1,059,970	0
	Montour SES			
316.0	Misc Power Plant Equipment	24,385	12,985	Amortize to O&M acct
	Subtotal -- Montour SES	24,385	12,985	0
	Subtotal -- Steam Production	1,940,209	1,210,869	0

R. J. Bernini

Pennsylvania Power & Light Company
Response to Interrogatories of the
Office of Trial Staff
Dated February 1, 1995
Docket No. R-00943271

Q. OTS-RB-41. Refer to Exhibit Future 1, Schedule D-11.

Recompute lines 14 thru 17 without a contingency factor, rate of inflation factor, or an earnings on the trust factor, for the DECON alternative. Supply supporting calculations.

A. OTS-RB-41. A recomputation of lines 14 thru 17 of Schedule D-11 to Exhibit Future 1 without a contingency factor, rate of inflation factor, or an earnings on the trust factor is set forth in Attachment 1.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Annual Accrual for Decommissioning Expense
Year Ended September 30, 1995
(Thousands of Dollars)

This adjustment provides for an annual accrual of decommissioning expense associated with the Susquehanna Steam Electric Station (SSES), based upon the total estimated cost of immediate dismantlement of the facility.

Line No.	Description	Amount: Unit 1	Amount: Unit 2	Amount: Total
1	Cost of decommissioning in 1993 dollars *	$ 296,129 ~~$350,574~~	$ 385,326 ~~$453,735~~	$ 681,455 ~~$804,239~~
2	PP&L share (90%)	$ 266,516 ~~$315,471~~	$ 346,793 ~~$ 408,361~~	$ 613,309 ~~$ 723,832~~
3	Rate of inflation	N.A. ~~4%~~	N.A. ~~4%~~	
	Years to Retirement			
4	Unit 1 (1994-2022)	N.A. ~~29~~		
5	Unit 2 (1994-2024)		N.A. ~~31~~	
	Cost of Decommissioning			
6	Unit 1 (line 2 ~~x 3.118651 (a))~~	$ 266,516 ~~$983,844~~		
7	Unit 2 (line 2 ~~x 3.373133 (b))~~		$ 346,793 ~~$1,377,456~~	$ 613,309 ~~$2,361,300~~
8	Value of trust @ 9/30/95	$56,548	$41,717	$98,265
9	Earnings on trust (c)	N.A. ~~5.50%~~	N.A. ~~5.50%~~	
	Value of Trust			
10	~~@ 2022~~ (line 8 ~~x 4.244401 (d))~~	$ 56,548 ~~$240,012~~		
11	~~@ 2024~~ (line 8 ~~x 4.724124 (e))~~		$ 41,717 ~~$197,076~~	$ 98,265 ~~$437,088~~
	Net Cost of Decommissioning			
12	Unit 1 (line 6 - line 10)	$ 209,968 ~~$743,832~~		
13	Unit 2 (line 7 - line 11)		305,076 ~~$1,180,380~~	$ 515,044 ~~$1,924,212~~
	Annuity Amount			
14	Unit 1 (line 12 ~~x .016955 (f))~~ ÷ 27 YRS.	$ 7,777 ~~$12,609~~		
15	Unit 2 (line 13 ~~x .014760 (g))~~ ÷ 29 YRS.		$ 10,520 ~~$17,433~~	$ 18,297 ~~$30,042~~
16	Less: Amount per budget	3.818	3.308	7.126
17	Increase in expense	~~$8,791~~ $ 3,959	~~$14,125~~ $ 7,212	~~$22,916~~ $ 11,171

a) Future value of $1 with compound interest @ 4% for 29 years.
b) Future value of $1 with compound interest @ 4% for 31 years.
c) Reflects an after-tax rate of return of 1.5% above the assumed rate of inflation.
d) Future value of $1 with compound interest @ 5.5% for 27 years.
e) Future value of $1 with compound interest @ 5.5% for 29 years.
f) Periodic deposit that will grow to $1 in 27 years with interest compounded @ 5.5%.
g) Periodic deposit that will grow to $1 in 29 years with interest compounded @ 5.5%.

* EXCLUDING CONTINGENCY

**PENNSYLVANIA POWER & LIGHT COMPANY
RESPONSE TO INTERROGATORIES
OF THE OFFICE OF CONSUMER ADVOCATE, SET II
DATED JANUARY 30, 1995
DOCKET NO. R-00943271**

Q.10. Please refer to the discussion of contingency contained on page 4-4 of the TLG Susquehanna Decommissioning cost estimate. Please provide a detailed explanation of how the contingencies are applied on a "line-by-line basis." Include in the explanation quantification of the different levels (percentage, etc.) of contingency, that are applied, and an explanation of the criteria or decision process used in the application of each different level.

A.10. The contingency percentage was derived using the methodology described in the Atomic Industrial Forum's National Environmental Studies Project report "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (AIF/NESP-036). Chapter 13 of Volume 1 describes the various components of a decommissioning cost estimate and the application of differing levels of contingency against the individual components or line items.

The derivation of the actual percentage(s) for the Susquehanna SES estimate can be seen in the detailed cost tables in Appendix C of TLG's decommissioning cost study. The following categories and associated line item contingency levels were used to develop the overall contingency values identified within the decommissioning cost estimate:

Engineering	15%
Utility and DOC Staff	15
Decontamination	50
Reactor/Internals Segmentation	75
Reactor/Internals Packaging	25
Reactor/Internals Transportation	25
Reactor/Internal Controlled Disposal	25
Contaminated Component Removal	25
Contaminated Concrete Removal	25

Conventional LSA Packaging	10
Conventional LSA Transportation	15
Conventional LSA Controlled Disposal	15
Non-contaminated Component Removal	15
Energy	15
Equipment Rental, Small Tools	15
Fees and Taxes	10
Capital Expenditures	15
Supplies/Consumables	25

D. A. Krall

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Trial Staff
Dated January 13, 1995

Docket No. R-00943271

Q.OTS-RB-21D. Provide a detailed chronological history of the Company's compliance with Phase I and Phase II of the CAAA of 1990.

A.OTS-RB-21D. The following is a chronology of actions taken by PP&L to comply with both Title IV (Phases I and II) and Title I (Northeast ozone non-attainment provisions) of the 1990 Clean Air Act Amendments:

Date	Plant	Action
1991	Brunner Island 1, 2, 3 and Martins Creek 1, 2	Coal contracts through 1999 (i.e., through Phase I)
12/30/91	Conemaugh 2	Complete installation of emission monitors
6/25/93	Conemaugh 1	Complete installation of Continuous Emissions Monitors (CEMs)
9/11/93	Brunner Island 1, 2, 3	Complete installation of CEMs
9/15/93	Keystone 2	Complete installation of CEMs
9/29/93	Keystone 1	Complete installation of CEMs
10/2/93	Sunbury 1, 2, 3, 4	Complete installation of CEMs
10/4/93	Martins Creek 1, 2	Complete installation of CEMs
10/18/93	Holtwood 17	Complete installation of CEMs
12/21/93	Brunner Island 1	Complete installation of Low NOx Burners (LNBs) for Titles I and IV
12/31/93	Conemaugh 2	Complete installation of LNBs for Titles I and IV
12/31/93	Conemaugh 2	Complete installation of volumetric flow measurement (CEMs)
2/28/94	Montour 1, 2	Complete installation of CEMs
3/11/94	Sunbury 3	Complete installation of LNBs for Titles I and IV
3/11/94	Sunbury 3	Complete precipitator upgrades for Phase I coal
4/28/94	Keystone 2	Complete installation of LNBs for Title I
4/29/94	Martins Creek 3, 4	Complete installation of CEMs
6/3/94	Montour 2	Complete installation of LNBs for Title I
6/10/94	Brunner Island 2	Complete installation of LNBs for Titles I and IV
7/22/94	Martins Creek 2	Complete installation of LNBs for Titles I and IV
7/22/94	Martins Creek 2	Complete precipitator upgrades for Phase I coal
9/23/94	Martins Creek 1	Complete installation of LNBs for Titles I and IV
9/23/94	Martins Creek 1	Complete precipitator upgrades for Phase I coal
12/3/94	Brunner Island 3	Complete installation of LNBs for Titles I and IV
12/18/94	Conemaugh 1	Complete installation of flue gas desulfurization system
12/30/94	Conemaugh 1	Complete installation of LNBs for Titles I and IV

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Trial Staff
Dated February 1, 1995

Docket No. R-00943271

Q.OTS-RB-44. Refer to Exhibit DAK-4.

For the generating plants which services lives have been shortened, has compliance with EPA clean air restrictions contributed to the service life modifications. If so, how was the buying or transferring of clean air credits used in the company's evaluations.

A.OTS-RB-44. As described in Statement 5, the Direct Testimony of Douglas A. Krall, the Company does view compliance with the requirements of the 1990 Clean Air Act Amendments as a potential threat to the long-term operation of these units. In particular, the Company is concerned that the need for significant reductions of NOx emissions under Title I of the Amendments and reductions of emissions of air toxics under Title III of the Amendments could create cost exposures which could erode the economic benefit of continued operation.

It is anticipated that, in their final resolution, the Title I requirements may have provisions for the transfer of reduction credits or for emissions averaging. However, because these elements are speculative at this point and because the basic compliance levels are not known, the Company has not factored the buying or transferring of NOx emissions credits into its evaluations.

It is anticipated that any Title III requirements are more likely to be command-and-control-type requirements under which there would be no provisions for the transfer of reduction credits.

One aspect of the Amendments which does involve a well-developed program of trading "credits" is the Title IV program of transferrable SO_2 emission allowances. The Company's evaluations of generating plants reflect this program. Currently, the Company anticipates burning lower sulfur fuels at Holtwood 17, Martins Creek 1 & 2, and Sunbury and, also, transferring allowances to these plants in order to bring them into compliance. Those allowances may be from other

PP&L plants or they may be purchased through the emission allowance market. The final determination will be a function of the cost of emissions reductions at other PP&L units compared to the price of emissions available in the market.

PENNSYLVANIA POWER AND LIGHT COMPANY
R-943271

PP&L FOSSIL-FIRED STEAM ELECTRIC STATIONS DISMANTLING COSTS

	TOTAL COST WITH CONTINGENCIES (1000'S $)	CONTINGENCY DOLLAR AMOUNTS (1000'S $)	CONTINGENCY PERCENT UTILIZED
HOLTWOOD 15& 16	$20,117	$2,746	15.81%
HOLTWOOD 17	$25,423	$3,437	15.63%
SUNBURY 1	$33,985	$4,793	16.42%
SUNBURY 2	$33,250	$4,698	16.45%
SUNBURY 3	$34,612	$4,875	16.39%
SUNBURY 4	$43,918	$6,089	16.10%
MARTINS CREEK 1	$35,799	$5,213	17.00%
MARTINS CREEK 2	$40,807	$5,866	16.79%
MARTINS CREEK 3	$46,239	$6,025	14.98%
MARTINS CREEK 4	$39,399	$5,133	14.98%
BRUNNER ISLAND 1	$57,775	$8,526	17.31%
BRUNNER ISLAND 2	$56,025	$8,298	17.39%
BRUNNER ISLAND 3	$66,528	$9,670	17.01%
MONTOUR 1	$58,540	$8,557	17.12%
MONTOUR 2	$84,972	$12,002	16.45%
TOTAL FOR ALL STATIONS	$677,389	$95,928	16.50%

* ALL DATA FROM EXHIBIT TSL 1, APPENDICES C THRU G

OTS Exhibit No. 2
Schedule 6

D. S. Hoch

Pennsylvania Power & Light Company
Response to Data Request of
Office of Trial Staff
March 21, 1995 Hearing (Tr. 121)
Docket No. R-00943271

Q.DR.OTS-1. Please break down, by year, cost of removal and salvage shown on Attachment 1 to the Company's response to OTS-RB-19D, by the following categories: steam production, nuclear production, transmission, distribution and general plant.

A.DR.OTS-1. Attachment 1 provides negative net salvage costs by category (steam production, nuclear production, hydro production, other production, transmission, distribution and general). Cost of removal and salvage credits by category are not available.

Negative Net Salvage

	Steam Production	Nuclear Production	Hydro Production	Other Production	Transmission	Distribution	General
Jan-90	407,612.72	18,665.72	0.00	0.00	11,088.46	763,515.97	2,413.78
Feb-90	403,126.28	19,342.92	10,984.96	0.00	737.03	291,191.71	4,701.53
Mar-90	1,412,729.91	47,460.45	0.00	0.00	7.90	668,627.18	(404.43)
Apr-90	452,253.28	118,471.65	17,605.76	0.00	(118,250.73)	535,597.91	33,886.60
May-90	390,637.02	122,832.69	21,341.08	1,674.00	9,236.22	192,116.16	12,199.86
Jun-90	323,983.43	91,425.84	6,233.11	0.00	109,639.36	644,007.98	16,201.60
Jul-90	30,030.50	110,233.50	(4,278.27)	0.00	9,361.35	478,214.71	19,782.53
Aug-90	126,982.63	101,733.92	19,773.29	0.00	(30,247.39)	730,189.97	2,462.61
Sep-90	237,573.13	295,114.66	3,707.15	0.00	88.60	366,517.30	496.55
Oct-90	1,435,596.50	254,672.85	(9,903.50)	0.00	27,764.59	748,125.87	10,617.32
Nov-90	595,712.29	316,432.98	(1,335.00)	0.00	1,939.39	569,550.70	11,605.31
Dec-90	768,723.96	640,923.11	573.78	0.00	(105,641.59)	580,306.53	19,918.85
Jan-91	129,581.44	101,915.82	1,518.69	0.00	2,728.02	539,832.71	1,335.23
Feb-91	521,726.01	336,778.54	0.00	0.00	2,641.57	538,636.76	26,039.00
Mar-91	670,759.69	95,780.66	14.55	1,144.00	0.00	(184,954.95)	48,827.04
Apr-91	442,310.53	693,535.28	0.00	7,441.22	3,528.72	721,034.22	1,555.66
May-91	(567,963.36)	429,840.38	2.04	3,046.43	1,768.61	1,071,047.43	(135.76)
Jun-91	350,802.27	524,652.96	0.40	2,477.79	359.17	766,406.87	1,279.49
Jul-91	2,761,297.44	465,878.33	1,113.25	0.00	16,178.16	696,781.34	57,277.06
Aug-91	1,417,078.52	5,082.66	44,825.65	5,121.71	2,988.12	826,850.54	8,195.36
Sep-91	(302,931.17)	239,905.14	1,593.84	23,255.26	6,805.45	528,545.22	16,536.08
Oct-91	300,592.07	145,558.95	961.25	18,455.97	11,063.59	934,323.20	(3,066.51)
Nov-91	763,023.69	98,159.06	3,332.30	3,742.39	394.10	605,824.20	24,415.35
Dec-91	403,791.19	2,407,635.20	13,323.38	(1,262.78)	(1,721.35)	749,616.47	18,538.81
Jan-92	559,320.39	212,504.26	36,957.25	(314,278.72)	4,999.67	808,755.41	3,246.67
Feb-92	263,599.80	909,390.05	46,241.59	74,942.69	(54,565.73)	712,031.98	(3,602.88)
Mar-92	205,189.46	2,068,367.74	93,763.36	(275,536.47)	10,599.08	322,212.33	3,765.99
Apr-92	460,154.79	1,421,353.60	66,503.25	161,028.30	1,117.91	739,487.75	(700.46)
May-92	653,579.27	452,477.37	48,196.04	230,813.97	21,873.18	492,693.97	1,746.75
Jun-92	950,879.58	534,847.46	38,429.96	186,192.14	22,103.49	551,433.87	(5,022.72)
Jul-92	389,220.15	439,797.64	30,570.41	144,692.35	26,016.04	531,792.31	(1,872.62)
Aug-92	139,771.58	341,479.85	40,623.01	24,889.57	34,457.23	623,894.48	(18,112.75)
Sep-92	(37,529.76)	580,939.63	70,556.85	20,539.37	670.84	718,487.38	50,404.66
Oct-92	312,703.75	849,827.00	11,560.40	13,495.66	33,638.64	665,266.58	(6,244.54)
Nov-92	198,453.55	261,730.58	(2,771.57)	(9,444.08)	2,793.19	519,235.46	(26,779.65)
Dec-92	421,758.95	841,778.72	1,492.62	9,757.10	61,918.35	854,173.68	74,660.60
Jan-93	121,157.50	227,747.86	13,476.67	(184.62)	9,121.89	491,899.95	44,752.87
Feb-93	184,543.61	370,215.15	17,406.60	15,743.09	1,077.96	680,950.47	19,259.59
Mar-93	178,441.26	(224,680.81)	7,467.65	3,835.84	2,218.23	677,252.70	51,071.03
Apr-93	659,454.85	475,348.32	11,064.53	587.27	1,914.87	234,986.00	29,453.28
May-93	564,880.09	247,142.46	2,272.59	13,276.95	147.81	755,917.63	116,662.41
Jun-93	599,881.94	31,620.70	3,646.40	4,775.63	980.28	866,534.78	66,676.11
Jul-93	1,467,222.24	484,636.91	8,827.56	5,061.44	9,938.85	949,592.05	26,654.42
Aug-93	2,437,329.81	786,637.85	30,751.24	(141.87)	27,324.98	452,189.67	(125,301.08)
Sep-93	425,956.50	310,600.02	1,179.92	7,927.85	1,680.41	707,337.40	(74,290.08)
Oct-93	586,424.17	1,230,826.33	351.93	(12,256.62)	12,782.02	919,053.57	17,716.46
Nov-93	313,427.53	802,691.14	1,135.45	(0.00)	15,329.18	611,127.02	36,044.79

Negative Net Salvage

	Steam Production	Nuclear Production	Hydro Production	Other Production	Transmission	Distribution	General
Dec-93	861,292.69	126,430.43	1,524.30	5,134.10	40,525.07	1,042,173.00	(26,347.57)
Jan-94	313,695.75	182,873.89	985.96	126,031.47	28,293.94	384,861.47	10,001.95
Feb-94	1,097,263.15	163,179.53	6,601.46	(630.36)	6,372.81	522,868.18	16,677.10
Mar-94	488,676.45	404,536.76	16,918.93	10,248.34	76,250.17	620,331.95	26,360.96
Apr-94	904,518.31	667,840.46	73,285.96	79.15	95,548.22	562,406.65	18,197.92
May-94	1,126,958.20	599,709.96	53,912.53	16,521.19	10,042.61	1,024,379.33	(8,588.70)
Jun-94	623,627.35	(97,929.28)	33,744.27	0.00	24,451.85	860,302.80	25,004.62
Jul-94	486,328.06	277,465.96	3,253.29	(132,027.70)	39,523.88	650,464.74	31,025.75
Aug-94	615,658.16	170,803.57	10,141.22	0.00	21,243.63	975,419.85	34,619.33
Sep-94	1,067,862.68	454,604.34	25,644.35	1,036.55	8,481.59	995,204.12	113,613.11
Oct-94	675,604.05	45,706.20	17,339.46	689.20	17,097.55	922,706.11	46,786.89
Nov-94	595,657.98	(24,468.32)	809.45	934.50	62,018.81	958,940.87	131,016.03
Dec-94	284,119.66	175,667.83	8,160.30	0.00	23,293.30	962,835.96	30,003.89

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OTS Statement No. 4 + Ex 4
Dated: April 14, 1995
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R-943271

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

DOCUMENT FOLDER

Direct Testimony

of

Charles T. Weakley, III

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Concerning:

Operating and Maintenance Expenses
Rate Base

PENNSYLVANIA POWER & LIGHT COMPANY
Docket No. R-00943271

SUMMARY OF ADJUSTMENTS

I AM RECOMMENDING THAT THE FOLLOWING REDUCTIONS BE MADE TO PP&L'S OPERATING AND MAINTENANCE EXPENSE AND RATE BASE CLAIMS.

DESCRIPTION		AMOUNT
EXPENSES:		
1.	POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (SFAS 106)	$ 1,561,000
2.	PENSION COSTS	$10,224,000
3.	"EARLY WINDOW"	
	SUSQUEHANNA UNIT 1	$ 894,000
	SUSQUEHANNA UNIT 2	$ 305,000
4.	ENVIRONMENTAL REMEDIATION PROGRAM	$ 1,304,000
5.	RATE CASE EXPENSE	$ 373,000
6.	UNCOLLECTIBLE ACCOUNTS EXPENSE	$ 1,234,000
7.	ONTRACK PAYMENT PLAN	$ 140,000
8.	SOCIAL PROGRAMS	$ 2,500,000
RATE BASE:		
1.	PENSION COSTS	$ 5,273,000
2.	CASH WORKING CAPITAL	$11,749,000

Q. STATE YOUR FULL NAME, EMPLOYER AND BUSINESS ADDRESS.

A. Charles T. Weakley, III. I am employed by the Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, Pennsylvania 17120.

Q. WHAT IS YOUR POSITION WITH THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. I am a Fixed Utility Financial Analyst in the Office of Trial Staff (OTS).

Q. WHAT ARE YOUR DUTIES AS AN ANALYST IN THE OTS?

A. My duties as an OTS analyst include participation in formal base rate proceedings as an expert witness, with responsibility for preparation and presentation of OTS exhibits, schedules and testimony. My education and professional background are set forth in Appendix A, which is attached.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend adjustments to Pennsylvania Power & Light Company's (PP&L or Company) operating and maintenance (O&M) expense and rate base claims.

EMPLOYER'S ACCOUNTING FOR POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (SFAS 106)

Q. WHAT ARE OTHER POST EMPLOYMENT BENEFITS (OPEBs)?

A. The term OPEBs refers to all benefits provided by a company to its retirees other than pension benefits. These benefits typically include, but are not limited to, medical and life insurance coverage for retirees and their dependents.

Q. WHAT IS SFAS 106?

A. In December of 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106 (SFAS 106). FASB is the entity responsible for establishing generally accepted accounting principles (GAAP) for business and industry, including rate regulated enterprises. SFAS 106 required employers to change from a pay-as-you-go (cash) method of accounting for OPEB's to an accrual basis of accounting for these costs for fiscal years beginning after December 15, 1992. The issuance of SFAS 106 was prompted by the increasingly large unrecorded OPEB obligations resulting from an aging population and escalating health care costs.

Q. WHAT CHANGES IN ACCOUNTING ARE REQUIRED BY SFAS 106?

A. SFAS 106 requires that OPEB costs be viewed as deferred compensation earned during the period of active employment. The estimated future OPEB costs must be charged to expense (accrued) during the same period an employee is providing the service necessary to earn these benefits.

Q. WHAT COSTS ARE REQUIRED TO BE RECOGNIZED UNDER SFAS 106?

A. SFAS 106 requires employers to record as a current cost, all OPEB benefits expected to be paid after retirement to employees and their dependents. There is also a "transition obligation" resulting from the changeover from pay-as-you-go to accrual accounting. This transition amount consists of the difference between the estimated present value of the accumulated OPEB costs not previously charged to expense and the net fair value of qualifying plan assets when SFAS 106 was implemented. SFAS 106 permits the transition amount to be charged to expense in one year, or to be amortized on a straight-line basis over a period up to 20 years.

Q. PLEASE EXPLAIN HOW OPEB COSTS HAVE TRADITIONALLY BEEN TREATED FOR RATEMAKING PURPOSES PRIOR TO SFAS 106.

A. The Commission has traditionally permitted prudently incurred OPEB costs to be recovered in rates on a pay-as-you-go basis.

Q. WHAT EFFECT HAS SFAS 106 HAD ON OPEB COSTS?

A. The adoption of SFAS 106 creates a significant increase in recorded OPEB costs when compared to traditional pay-as-you-go accounting. The cumulative deferral of OPEB costs resulting from these different accounting methods is likely to increase for many years. The accounting profession is concerned with the probability of these deferrals not being recovered in future rates.

Q. HOW WAS THIS CONCERN ADDRESSED BY THE ACCOUNTING PROFESSION?

A. There is an existing FASB Statement that provided initial guidance to the accounting profession in the form of SFAS 71 <u>Accounting for the Effects of Certain Types of Regulation</u>. Among other things, SFAS 71 states that if regulation provides assurance that incurred costs will be recovered in the future, companies are required to capitalize these costs. Such capitalized costs are referred to as regulatory assets. SFAS 71 also provides that if these costs cannot be capitalized, generally accepted accounting principles require the regulated firm to charge the costs to current income.

Q. WHAT POSITION DID THE FASB TAKE WITH REGARD TO RECORDING A REGULATORY ASSET FOR DEFERRED OPEB COSTS?

A. The Emerging Issues Task Force (EITF) is a task force established by the FASB to provide assistance in the early identification and resolution of issues and problems affecting financial reporting. Agreement of 11 of EITF'S 13 members is required to reach a consensus position. When approved by the FASB, this position then becomes a part of generally accepted accounting principles applied to business and industry, including rate-regulated enterprises. On January 21, 1993, the EITF adopted a consensus position concerning the recording of regulatory assets for OPEB costs not currently recovered in rates.

The EITF adopted the following criteria that must be met in order for utilities to record a regulatory asset under SFAS 71 for unrecorded OPEB costs.

(a) A determination must be made that the recovery of the deferred costs (regulatory asset) is probable in the future.

(b) The following criteria must be met to establish probable future recovery:

1. The regulator must issue a rate order (or policy statement) allowing for the deferral of SFAS 106 costs and the subsequent inclusion of the deferred costs in rates.
2. The deferral of SFAS 106 costs should not exceed a period of five years. Annual SFAS 106 costs (including amortization of the transition amount) should be based on full accrual accounting and should be included in rates within five years.
3. The combined deferral/recovery period authorized by the regulator for the regulatory asset should not exceed 20 years.

Q. WHAT ARE THE CONSEQUENCES TO A UTILITY IF THESE CRITERIA ARE NOT MET?

A. For financial accounting purposes, the difference between the pay-as-you-go costs and the SFAS 106 costs that are disallowed would be charged against earnings in the period in which the disallowance occurs.

Q. HAS THE COMMISSION ADOPTED A POLICY STATEMENT ADDRESSING THIS ISSUE?

A. Yes. On May 20, 1993 at Docket M-00930415, the Commission entered an Order entitled Re: Policy Statement for Implementation of SFAS 106.

Q. **PLEASE SUMMARIZE THE COMMISSION'S POLICY STATEMENT.**

A. The essential elements of the Policy Statement, as set forth in Annex A to that Order are as follows:

> 1. Each jurisdictional utility which has: (1) satisfied the appropriate customer notice requirements; (2) presented sufficient documentation to support its SFAS 106 cost estimates; and (3) presented sufficient cost containment measures, may seek formal Commission approval to record on its books a regulatory asset pursuant to SFAS 71 equal to the difference between its current rate recognition of OPEB costs and its accrued liability for such expenses under SFAS 106 subject to recovery in future rate proceedings to the extent that such costs are prudently incurred and demonstrated to be reasonable.
>
> 2. The funding of a dedicated trust for the deferred amounts is not required at this time. A utility should maintain separate balance sheet accounts for both the accrued liability and the regulatory asset along with sufficient records to allow a detailed analysis of such accounts.
>
> 3. The Commission intends to move jurisdictional utilities to SFAS 106 accrual accounting for ratemaking purposes within approximately five years and to allow the recovery in base rates of deferred amounts in approximately 20 years, to the extent that OPEB costs are prudently incurred and examined for reasonableness in a base rate proceeding prior to rate recognition.

> 4. If the Commission, after examination, grants current rate recognition of OPEB costs exceeding the pay-as-you-go amount, the excess amount should be placed in a dedicated trust fund.

Q. HAS PP&L RECEIVED PERMISSION TO DEFER THE INCREMENTAL OPEB COSTS OR TO ESTABLISH A REGULATORY ASSET FOR SUCH COSTS IN ANY PRIOR PROCEEDING BEFORE THE COMMISSION?

A. Yes. On December 4, 1992, the company filed a petition with the Commission requesting permission to defer the incremental OPEB costs that the company was required to recognize beginning January 1, 1993. By Order entered May 6, 1993, the Commission approved the company's petition.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL FOR RECOVERING SFAS 106 COSTS.

A. The Company's SFAS 106 claim of $ 27,654,000 is presented at PP&L Exhibit Future 1, schedule D-6. The $ 27,654,000 consists of the following:

Incremental Costs	$ 13,415,000
Pay-as-you-go	$ 12,442,000
Current SFAS 106 Costs	$ 25,857,000
Amortization of the Deferred Expense	$ 1,797,000
	$27,654,000

Q. WHAT ARE THE COMPONENTS OF THE $ 27,654,000 OF SFAS 106 COSTS CLAIMED BY THE COMPANY?

A. The $ 27,654,000 consists of two components. The Company is requesting that it be permitted to recover current (ongoing) SFAS 106 costs in the amount of $ 25,857,000 which includes the transition obligation amortized over 20 years in the amount of $8,692,000. The incremental cost of $ 13,415,000 is the difference between full accrual accounting as required by SFAS 106 and the pay-as-you-go or cash basis of accounting for these costs.

The second component, of $ 1,797,000, represents a 17.3 year amortization of the $ 31,095,000 of deferred OPEB costs which the Company claims has been accumulated for the period January 1, 1993 (when SFAS 106 was adopted) to September 30, 1995. The $ 31,095,000 consists of $ 10,770,000 for calendar year 1993, $ 8,711,000 for the nine months ended September 30, 1994 and $ 11,614,000 for the twelve months ended September 30, 1995. See OTS Exhibit No. 4, Schedule No. 6.

Q. MR. WEAKLEY, WHAT IS YOUR RECOMMENDATION REGARDING PP&L'S CLAIM FOR THE RECOVERY OF SFAS 106 COSTS?

A. My recommendation is that the recovery of $1,797,000 for the 17.3 year amortization of the deferred expense of $31,095,000 be denied. This will reduce O&M expenses by $1,561,000 on a Pennsylvania jurisdictional basis. See OTS Exhibit No. 4, Schedule 1.

Q. WHY HAVE YOU RECOMMENDED THAT THE $ 1,797,000 FOR THE 17.3 YEAR AMORTIZATION OF THE $ 31,095,000 OF ACCUMULATED DEFERRED OPEB EXPENSES BE DENIED?

A. I have been advised by counsel that the claim for the deferred expense of $ 1,797,000 violates the prohibition of retroactive ratemaking supported by the Commonwealth Court Order of May 26, 1994, Popowsky v. Pennsylvania Public Utility Commission, 642 A.2d 648 (1994).

PENSION EXPENSE

Q. WHAT IS A PENSION FUND?

A. A pension fund is a trust established to receive actual cash contributions by the Company for the benefit of its employees.

Q. PLEASE DISCUSS AND COMPARE THE TWO PENSION EXPENSE CALCULATIONS THAT ARE REQUIRED TO BE MADE ANNUALLY.

A. There are two pension expense calculations that are computed annually by a company's actuary; SFAS 87 pension expense and the pension contribution that must be made to comply with ERISA (Employee Retirement Income Security Act) and IRS rules.

SFAS 87 requires a specific calculation be used in determining pension expense. This expense amount is included in the financial statements of all companies. The purpose of SFAS 87 is to allow the user of the financial statements to compare the pension plans and expenses among different companies. SFAS 87 does not address funding requirements of the plan or the ratemaking treatment of the expense and should not be used for any purpose other than satisfaction of the requirements of SFAS 87.

The SFAS 87 pension expense is accrued on the books of a company and is adjusted at year end to the actuarially determined amount. There are no payments made to the pension plan for the SFAS 87 pension expense since this expense does not represent a company's pension liability but rather represents the amount that must be recorded on a company's books in order to comply with Generally Accepted Accounting Principles (GAAP).

The second calculation performed by the actuary is the determination of a company's annual pension contribution computed in compliance with ERISA and IRS rules. It is this calculation that requires a payment into the pension plan.

The difference between the cash contribution and the book expense will be recorded on the books as a prepaid asset where the payment exceeds the expense or as a liability if the payment is less than the expense.

Q. WOULD YOU PROVIDE A BRIEF HISTORICAL OVERVIEW OF THE RATEMAKING TREATMENT FOR PENSION FUND EXPENSE?

A. Yes. In the past the Commission has allowed rate relief to utilities based on the actual cash contribution required to be paid into the pension fund. The contributions are based on an actuarial report which is prepared annually. Contained in the actuarial report is the actual present value of the fund (assets), as well as the anticipated liability of the fund. The liability is the amount determined by the actuaries that is required to meet the benefits payable to the employees at any given time. Due to higher than anticipated earnings on the fund deposits, many pension funds have been "overfunded". This means that the pension funds contain assets in excess of the fund liabilities. As a result, companies are not required to make any pension contributions, nor are they allowed by law to do so until the liabilities exceed the assets. This has been the case with PP&L.

Q. PLEASE EXPLAIN THE COMPANY'S PENSION EXPENSE CLAIM.

A. The Company's pension expense claim is presented in OTS Exhibit No. 4, Schedule No. 7. In this case, PP&L proposes to change from a cash to an accrual basis of accounting for pension expense under SFAS 87. The Company is requesting the SFAS 87 pension expense of $ 10,224,000 and rate base of $ 5,273,000 for the capitalized portion on a PUC jurisdictional basis.

Q. DO YOU AGREE WITH THE COMPANY'S PENSION EXPENSE CLAIM?

A. No, I do not. The Company's claim for pension expense should be limited to the annual pension contribution calculated by the Company's actuary in compliance with ERISA and IRS rules. In this instance, there is no cash contribution required. Since 1988, the maximum allowable and minimum required contribution level has been zero for PP&L.

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S CLAIM?

A. I recommend that the Company's claim for pension expense be disallowed in its entirety. This adjustment will reduce, on a PUC Jurisdictional basis, O&M expenses by $10,224,000 and rate base by $5,273,000. Reference OTS Exhibit No. 4, Schedule No. 2.

The ratemaking claim for pension expense should be based on a company's cash contributions to the pension funds. The pension fund is an entity separate from the Company with its own assets, liabilities, revenues and expenses. However, a company is required to make contributions to the fund subject to minimum ERISA (Employee Retirement Income Security Act) limitations and maximum limitations of the Internal Revenue Code. These rules insure that the contributions are sufficient to meet future obligations and do not result in excessive asset levels. The amount contributed to the fund is determined by the actuary and is based on a company's funding policy.

Q. WHAT IS THE BASIS FOR YOUR PENSION EXPENSE ADJUSTMENT?

A. The fact that the actuarial report shows the pension fund to be overfunded is the basis for my adjustment. As a result of the overfunding, no contributions are required for the future test year; nor are any tax deductible contributions allowed under current Internal Revenue Service regulations. The Company's last contribution was made on June 3, 1988. PP&L's intention is to begin making cash contributions (if allowed) sometime during the third quarter of 1996. However, the 1996 plan year contributions (if allowed) do not actually have to be made until March 15, 1998.

Q. MR. WEAKLEY, WILL YOU EXPLAIN WHY YOUR PENSION EXPENSE ADJUSTMENT WOULD AFFECT RATE BASE?

A. Yes. When an employee's time is charged to a capital project (as oppose to O&M expense), the value of the payroll and employee benefits are then added to the cost of the capital project which will be included in the Company's rate base.

"EARLY WINDOW" DEFERRALS - SUSQUEHANNA UNITS 1 & 2

Q. WHAT ARE "EARLY WINDOW" DEFERRALS?

A. Early window deferrals, with respect to electric utilities, are accounting mechanisms which allow for the timing differences between the date of commercial operation and base rate recognition of a generating facility. Simply, the early windows allowed PP&L to accumulate these costs in a deferred account.

Q. WHAT GENERATING FACILITIES ARE INCLUDED IN PP&L'S CLAIM FOR EARLY WINDOW DEFERRALS IN THIS PROCEEDING?

A. The Company has claimed Early Window Deferrals for Susquehanna Units 1 and 2. Susquehanna Unit No. 1 went into service on June 8, 1983 and was recognized in rates effective August 22, 1983 pursuant to the Commission's Order entered on August 22, 1983 at Docket R-822169. Susquehanna Unit No. 2 went into service on February 12, 1985 and was recognized in rates effective April 26, 1985 pursuant to the Commission's Order entered on April 26, 1985 at Docket R-842651.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S "EARLY WINDOW" CLAIMS.

A. The Company's adjustment amortizes the "early window" deferrals applicable to Susquehanna Units 1 and 2 over a period of ten years. The annual amortization claim for unit 1 is $894,000 and for unit 2 is $ 305,000. See PP&L Exhibit Future 1, schedule D-14. Early window deferrals for Units 1 and 2 were authorized by the Commission in its Orders at Docket Nos, P-820367, entered July 29, 1982 and P-830461, entered November 9, 1983 respectively. Approval was granted for accounting purposes only.

Q. WHAT IS THE OTS POSITION ON THE RECOVERY OF THESE DEFERRED EXPENSES?

A. I have been advised by counsel that these early window claims should be disallowed because PP&L did not make the claim to recover these expenses at its first opportunity and the recovery constitutes impermissible retroactive ratemaking. In the case of Unit 1, the company had the opportunity to make a claim to recover the associated early window costs in its 1984 base rate case. For Unit 2, the company could have filed at an earlier date and not waited ten-years to seek recovery of these costs.

ENVIRONMENTAL REMEDIATION EXPENSE

Q. WHAT ARE ENVIRONMENTAL REMEDIATION PROGRAM EXPENSES?

A. The environmental remediation program is intended to proactively reduce the environmental liabilities that result from standard past practices at operating facilities. The environmental remediation expense is the costs of cleaning up various sites including manufactured gas plants, substations, utility pole sites with PCB spill histories and decommissioned power plants.

Q. WHAT IS THE COMPANY'S CLAIM FOR ENVIRONMENTAL REMEDIATION PROGRAM EXPENSES?

A. The environmental remediation expense claimed on PP&L Exhibit Future 1, Schedule D-16 is $5,400,000. This claim is based on the estimate of environmental assessments / remediation payments expected to be made during 1995.

Q. **WHAT IS YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S CLAIM FOR ENVIRONMENTAL REMEDIATION PROGRAM EXPENSES?**

A. I am recommending that the Company's remediation expense claim be reduced by $ 1,304,000. See OTS Exhibit No. 4, Schedule 3.

Q. **WHAT IS THE BASIS FOR YOUR ADJUSTMENT?**

A. In my opinion, the Company's claimed level of expense is speculative and not supportable based upon recent experience. The Company's claim is based on estimates of potential future costs. I reviewed the actual remediation expenses of $1,450,854 for the historic test year. In determining a normal level of expense, rather than treating the historic test year as representative of the future, I liberally used the highest monthly expenditure for the historic test year of $316,000 (May, 1994) and annualized it to develop a level of expense for the future test year of $3,800,000 ($316,000 x 12) which is 262 percent higher than the historic test year. Reducing the Company's claimed future test year expense of $5,400,000 to the OTS' recommended level of $3,800,000 results in a reduction on a total Company basis of $1,600,000. Then applying the PUC jurisdictional allocation of 81.4815% results in my recommended disallowance of $1,304,000.

RATE CASE EXPENSE

Q. IN THIS PROCEEDING, THE COMPANY HAS MADE A CLAIM FOR RATE CASE EXPENSE. WOULD YOU BRIEFLY EXPLAIN THE NATURE AND TYPE OF EXPENSES CLASSIFIED AS RATE CASE EXPENSE?

A. The estimated costs that comprise a company's allowable claim for rate case expense are those that are incurred to compile, present and defend a request for a base rate increase before the Commission. The estimated costs that are typically found in a rate case expense claim includes legal fees for outside counsel, outside consultants and the cost of printing, collating and postal expenses.

Q. HOW IS THE COMMISSION TREATING RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission views prudently incurred rate case expense as an ongoing, although recurring at irregular intervals, expense relative to the rendering of the utility service; thus subject to normalization for ratemaking purposes. A company's history regarding the frequency of rate case filings is an essential element in determining the normalized level of rate case expense for ratemaking purposes.

Q. HOW SHOULD THE FREQUENCY OF RATE CASE FILINGS BE DETERMINED?

A. The frequency should be determined by computing the average number of months that expire between the filing dates of a company's base rate case filings. The number of base rate case filings used to compute the average is a matter of judgment.

Q. AFTER DETERMINING THE FILING FREQUENCY OF BASE RATE FILINGS, HOW IS THE NORMALIZED EXPENSE CLAIM DETERMINED?

A. The estimated rate case expenses are multiplied by a fraction, the numerator being 12 months and the denominator the number of months representing the frequency of filings.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE IN THIS PROCEEDING?

A. The company's claim for rate case expense totals $1,491,000.

Q. HOW WAS THE COMPANY'S CLAIM DEVELOPED AND WHAT TREATMENT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company's claim has been estimated and can be itemized as follows:

1) Legal Fees	
- Morgan, Lewis & Bockius	675,000
2) Witnesses/Consultants	
- TLG Services, Inc.	250,000
- P. Moul & Associates	40,000
- Putnam Hayes & Bartlett, Inc.	200,000
- Coopers & Lybrand, LLP	100,000
- Towers & Perrin	110,000
- HRN	35,000
- Deloitte & Touche	10,000
3) Employee Expenses	20,000
4) Printing & Advertising	40,000
5) Miscellaneous	11,000
Total	$1,491,000

PP&L has reflected a 2-year normalization of rate case expense applicable to this proceeding. This was based on the 2-year period approved in PP&L's last base rate case. The company is claiming a rate case expense of $746,000 ($1,491,000 \ 2). This adjustment is found in PP&L Exhibit Future 1, Schedule D-7.

Q. **WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?**

A. My recommendation is that rate case expense be normalized over a 4-year period. This adjustment will reduce expenses by $373,000 as shown in OTS Exhibit No. 4, Schedule 4.

Q. **WHAT IS THE SUPPORTING RATIONALE FOR YOUR POSITION?**

A. It has been 10-years since PP&L was in for a base rate case. See OTS Exhibit No. 4, Schedule No. 5. Thus, recent history could support a ten year normalization. However, I have looked at a twenty year period. For the last twenty years filing intervals have occurred at approximately every four years.

UNCOLLECTIBLE ACCOUNTS EXPENSE

Q. **IN THIS PROCEEDING THE COMPANY HAS MADE A CLAIM FOR UNCOLLECTIBLE ACCOUNTS EXPENSE. WOULD YOU BRIEFLY DEFINE WHAT IS MEANT BY UNCOLLECTIBLE ACCOUNTS?**

A. Uncollectible accounts are specific receivables that are determined to be uncollectible in whole or in part, either because the debtors cannot pay or because the creditor finds it impracticable to enforce payment. Those accounts deemed uncollectible are charged against income.

Q. HOW DO UTILITIES GENERALLY RECOGNIZE UNCOLLECTIBLE ACCOUNTS FOR RATEMAKING PURPOSES?

A. Generally for ratemaking purposes, utilities compute uncollectible accounts expense on an annual prospective basis. While the uncollectible accounts expense is a prospective claim, its genesis begins with an historic analysis of actual net write-offs to gross revenues and the development of an historic write-off ratio. Net write-offs are gross write-offs less recoveries of amounts previously written-off. This ratio is then applied to projected revenues to determine the proper prospective allowance.

Q. HAVE UTILITIES DEVIATED FROM THE METHODOLOGY JUST DISCUSSED TO DEVELOP THEIR PROSPECTIVE UNCOLLECTIBLE ACCOUNTS EXPENSE CLAIM?

A. Yes. While the vast majority of utilities develop their claim in the manner just described, situations may arise wherein the historic analysis is not representative of the future and therefore will not produce an accurate prospective claim. Those situations occur when there exists a definite upward or downward trend in actual write-offs. Because the generally accepted methodology is designed to levelize any fluctuations in actual write-off activity by the Company it may not be an accurate predictor of prospective actual write-offs when a clear trend is evident.

Secondly, a change in collection procedures could also invalidate an historic analysis if it can be demonstrated that the procedural changes would produce increased or decreased write-off activity.

Q. **WHAT IS THE COMPANY'S CLAIM FOR UNCOLLECTIBLE ACCOUNTS EXPENSE IN THIS PROCEEDING?**

A. The Company has claimed $16,932,000 for uncollectible accounts expense. The total expense is comprised of three elements: an amount of $16,800,000 for uncollectible electric service accounts receivable, $120,000 for property damage accounts receivable and $12,000 in other accounts receivable, (Reference OTS Cross Examination Exhibit No. 9).

Q. **HOW WAS THE CLAIM OF $16.8 MILLION FOR UNCOLLECTIBLE ELECTRIC SERVICE ACCOUNTS RECEIVABLE DEVELOPED BY THE COMPANY?**

A. The Company separated receivables into three categories: receivables referred for collection, receivables related to deferred payment plans and receivables related to accounts that are current to over 90 days delinquent. To these amounts the Company applied write-off percentages that were based on historical experience and adjusted for known changes. These percentages were then used to develop an uncollectible accounts provision requirement of

$30,719,000. The provision balance at October 1, 1994 is $29,485,000. When the beginning balance of $29,485,000 is reduced by 1995 projected write-offs of $15,566,000 a net provision of $13,919,000 remains. The $16,800,000 is the funding required to restore the provision to the projected requirement of $30,719,000 ($16,800,000 + $13,919,000). The Company's computations are detailed at OTS Cross Examination Exhibit No. 9, Attachment 1.

Q. **ARE YOU IN AGREEMENT WITH THE COMPANY'S CLAIM FOR UNCOLLECTIBLE ACCOUNTS EXPENSE?**

A. No, while I take no exception as to how the projected uncollectible provision of $30,719,000 was calculated for book purposes, I am in disagreement with what should be the appropriate claim for ratemaking purposes.

Q. **WHAT DO YOU RECOMMEND AS THE APPROPRIATE ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS EXPENSE?**

A. I recommend an allowance of $15,698,000 which represents a proposed reduction of ($1,234,000) to the Company claim of $16,932,000. My recommended uncollectible expense allowance is comprised of the following elements:

Electric Service Accounts Receivable	$15,566,000
Property Damage Accounts Receivable	120,000
Other Accounts Receivable	12,000
	$15,698,000

Q. HOW DOES YOUR PROPOSED ALLOWANCE DIFFER FROM THE COMPANY'S CLAIM?

A. The difference is in the amount of uncollectible accounts expense related to uncollectible electric service accounts receivable. Of the total Company claim, $16.8 million applies to electric service accounts receivable, as described above.

As I previously stated, the Company has developed an uncollectible accounts provision requirement of $30,719,000. The claim of $16.8 million is the amount of dollars needed to fund the reserve to the Company's projected requirements of $30,719,000 (Tr. 476, L 18-22). The $16.8 million does not reflect the Company's projected actual write-offs. The Company has projected actual 1995 write-offs of $15,566,000 (reference OTS Cross Examination Exhibit No. 9). My proposed allowance incorporates the $15,566,000 rather than the $16,800,000 into the development of the total uncollectible accounts expense claim.

Q. HOW HAVE THE COMPANY'S ACTUAL NET WRITE-OFFS COMPARED TO THE ANNUAL CHARGES TO FUND THE PROVISION?

A. The following is a comparison of the future test year and the three immediate prior years:

	Actual Write-Offs	**Expense to Fund Provision**
FTY 9/30/95	$15,566,499	$16,800,000
FYE 9/30/94	$16,761,586	$17,368,000
FYE 9/30/93	$16,361,087	$16,495,000
FYE 9/30/92	$18,306,755	$19,161,000
TOTAL	**$66,995,927**	**$69,824,000**

Q. WHY SHOULD THE RATEMAKING ALLOWANCE REFLECT ACTUAL PROJECTED NET WRITE-OFFS?

A. Ratepayers should be expected to reimburse the utility for a normalized projected level of uncollectible accounts expense based on the actual direct write-offs that will occur and not arbitrary amounts related to funding a reserve. As can be noted from the schedule in the previous response, actual write-offs show a decreasing trend. This has occurred even though revenues have been increasing (Reference OTS Exhibit No. 4, Schedule 14, Page 3). This trend is not as apparent in the charges to fund the provision.

Q. DOES YOUR PROPOSED REDUCTION OF ($1,234,000) REPRESENT THE TOTAL ADJUSTMENTS THAT YOU PROPOSE TO UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. I am proposing an additional adjustment to uncollectibles related to the Company's customer assistance program.

ONTRACK PAYMENT PROGRAM

Q. WOULD YOU BRIEFLY DESCRIBE THE COMPANY'S CUSTOMER ASSISTANCE PROGRAM PROPOSAL?

A. PP&L has formulated a customer assistance program (CAP) and has claimed funding for that program in this proceeding. PP&L refers to its CAP as the OnTrack Payment Program (OTPP). The pilot program will encompass 2,000 residential customers, whose household incomes are at or below 150 percent of the federal poverty level guidelines. These customers currently are unable to pay the full cost of service related to their electric usage. PP&L has proposed a program designed to establish an affordable monthly payment based on the customer's ability to pay a percentage of their income for electric service.

Q. WHAT IS THE COMPANY'S CLAIM FOR OTPP?

A. The Company is claiming $942,625 in OTPP related expenses (Tr. 871). The total claim is comprised of two distinct elements. An amount of $232,625 is being claimed for administrative costs related to enrollment, recertification, follow-up interviews and an outside evaluation of the program. An additional $710,000 is claimed within uncollectible accounts expense. The $710,000 is broken down between $322,000 in revenue shortfall or billing deficiency and $388,000 in arrearage forgiveness.

Q. HOW WAS THE UNCOLLECTIBLE EXPENSE PORTION OF THE OTPP FUNDING DETERMINED?

A. As I previously stated the $710,000 claim in uncollectible accounts expense is comprised of two elements. The average revenue shortfall of $322,000 was based on an average revenue shortfall of $161 times 2,000 potential OTPP customers. The average arrearage forgiveness of $388,000 was based on an average arrearage forgiveness of $194 times 2,000 potential OTPP customers. (Tr. 874). The averages of $161 and $194 respectively were based on the actual experience of the approximate 1,000 customers currently on OTPP.

Q. MR. WEAKLEY, ARE YOU IN AGREEMENT WITH THE OTPP FUNDING LEVEL REQUESTED IN THIS PROCEEDING?

A. No. The Company's claim is excessive. I propose a reduction of $140,000 to the Company's claim of $710,000 in uncollectible accounts expense. Reference OTS Exhibit No. 4, Schedule 8.

Q. HOW HAS THE COMPANY OVERSTATED THE FUNDING REQUIREMENT RELATIVE TO THE UNCOLLECTIBLE ACCOUNTS PORTION OF THE OTPP?

A. The Company has overstated its expense claim by failing to give recognition to potential LIHEAP (Low Income Home Energy Assistance Program) funding. As a condition of enrollment, the OTPP customer must apply for a LIHEAP grant. The Company has projected the average LIHEAP grant at $233 per customer (Tr. 879). For 2,000 OTPP customers that projects to $466,000 in additional revenues that the Company has not recognized. I have reduced the total LIHEAP grants offset by 70% to reflect that a portion of these customers will be non-heating however, the program should be tailored to those customers with the greatest need. The uncollectible accounts expense related to the OTPP should be reduced by $140,000 to $570,000 ($710,000 - $140,000).

I would note that this adjustment is separate and distinct from the uncollectible accounts adjustment I addressed earlier in my testimony.

SOCIAL PROGRAMS

Q. WHAT IS THE NATURE OF THE SOCIAL PROGRAMS BEING PROPOSED BY PP&L AND THE FUNDING BEING REQUESTED IN THIS PROCEEDING?

A. PP&L has introduced six new social programs and proposed enhancements to two existing programs. The total projected funding requirement for these programs is $6,700,000 with $3,530,000 to be funded by ratepayers and $3,170,000 to be funded by PP&L. The eight programs and ratepayer requested funding is as follows:

PROGRAM	TOTAL FUNDING $	RATEPAYER FUNDING $
1. Build-A-Neighborhood	2,000,000	1,000,000
2. Affordable Housing	2,000,000	1,000,000
3. Small Business	1,250,000	500,000
4. Winter Emergency Plan	250,000	- 0 -
5. Keep Warm Plan	1,000,000	1,000,000
*6. Operation Help	50,000	- 0 -
*7. Cares	30,000	30,000
8. Payment Protection Plan	120,000	- 0 -
TOTAL	6,700,000	3,530,000
* Existing Programs		

Q. WHAT WAS THE ORIGIN OF THESE PROGRAMS?

A. The genesis of the programs was a PP&L report by the Social Initiatives Task Force entitled "**PP&L Partners: Communities in Action**" dated November 14, 1994. The purpose of the report was to identify customer and community needs and recommend social initiatives to address those needs. (Reference OTS Cross Examination Exhibit No. 14).

Q. WHAT IS THE SOCIAL INITIATIVES TASK FORCE?

A. The Social Initiatives Task Force is a collection of seven PP&L employees. The job responsibilities of these employees relate to either consumer affairs, public affairs, marketing or market research.

Q. HAVE ANY OF THESE PROGRAMS PREVIOUSLY BEEN SUBMITTED TO THE COMMISSION FOR APPROVAL?

A. No, none of these programs were previously submitted to the Commission. PP&L is seeking approval of these programs and the related funding in this proceeding.

Q. WOULD YOU PROVIDE A BRIEF DESCRIPTION OF THESE PROGRAMS?

A. Yes. However, I will address only those five programs for which PP&L is requesting a direct ratepayer contribution. Those programs are as follows:

1. ***Build-A-Neighborhood Program*** - PP&L would support local community organizations' efforts to improve urban neighborhoods. Services would include weatherization, upgraded street lighting, heating system replacements, home repairs, clean-up and painting, sidewalk/curbing repair, etc.

2. ***Affordable Housing Program*** - PP&L would support efforts to promote home ownership for limited income families. Major activities would include buying properties, providing weatherization, installing heat pump water heaters and paying for closing costs.

3. ***Small Business Program*** - PP&L would provide free weatherization services, forgive demand charges, make funding available for start-up businesses and provide a mentoring service.

4. ***Keep Warm Plan*** - PP&L would provide weatherization measures, heat pump water heaters and compact fluorescent lighting to the working poor. The working poor are those customers whose income is just above federal poverty guidelines and therefore disqualifies them from existing programs.

5. *Cares* - PP&L wants to establish a pilot program for 250 non-CARES customers who have low-income indicators on their accounts. CARES representatives would verify income, establish and monitor payment plans and conduct follow-up.

Q. WHAT ARE PP&L'S OBJECTIVES FOR THESE SOCIAL INITIATIVES?

A. The Company lists four objectives for these social initiatives (reference OTS Cross Examination Exhibit No. 16, Page 2 of Attachment 1). Those objectives are to (1) provide meaningful cost-beneficial services; (2) demonstrate PP&L's commitment to addressing social concerns; (3) offer a significant financial commitment for program development and implementation; and (4) enhance PP&L's role and visibility in service area communities. I will comment on these objectives later in my testimony.

Q. DOES THE $3,530,000 REQUESTED FROM PP&L'S RATEPAYERS REPRESENT THE TOTAL COST FOR THESE PROGRAMS?

A. No. There are hidden costs that would accrue to each program basically in the form of payroll and benefit costs. These are ambitious programs that may require considerable amounts of human resources. Each program will be implemented, monitored and coordinated by various employees of PP&L. The Company has not quantified what the additional costs would be in terms of payroll and benefit costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THESE PROGRAMS?

A. I must emphasize that I do not dispute that these are well-intentioned programs just as most charities are well-intentioned. However, from a regulatory perspective I must recommend total disallowance of the costs related to the Build-A-Neighborhood, Affordable Housing and Small

Business Programs. The disallowance of these programs results in a reduction of $2.5 million to the Company's overall claim of $3,530,000 for social programs.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED DISALLOWANCE OF THESE PROGRAMS?

A. The basis for my recommended disallowance is rooted in four main areas. First, these programs are not driven by specific Commission approved regulatory goals. Second, there is no discernable benefit to ratepayers. Third, these programs are being funded by forced contributions. Fourth, these programs are not compatible with the competitive environment evolving in the electric industry. In addition, I have been advised by counsel that ratepayer funding of these programs is illegal.

Q. MR. WEAKLEY, WOULD YOU ELABORATE ON YOUR STATEMENT THAT THESE PROGRAMS LACK A SPECIFIC REGULATORY GOAL?

A. Yes. These programs in general are designed to achieve social benefits that accrue to local communities and society at large. They are not driven by a regulatory goal aimed at achieving direct benefits to ratepayers. The fact that benefits may or may not materialize is secondary to the overall intent of these programs.

Q. WILL THESE PROGRAMS RESULT IN COST SAVINGS TO RATEPAYERS?

A. That is unknown. As confirmed by PP&L witness Mr. Stathas, no cost benefit analysis has been conducted by PP&L with respect to these programs (Tr. 892).

Q. HASN'T PP&L LISTED LOWER ACCOUNTS RECEIVABLE WRITE-OFFS AS ONE OF THE BENEFITS OF SOME OF THESE PROGRAMS?

A. Yes, PP&L lists lower accounts receivable write-offs as a potential benefit under the Build-A-Neighborhood Program and Affordable Housing Program. However, it remains pure speculation as to whether any net savings will develop. At this point in time the specifics of these programs, such as who will be eligible and the characteristics of program participants, have not been developed.

Under the Build-A-Neighborhood and Affordable Housing Programs, to the extent the benefits of these programs are extended to non-electric heating customers, no benefits will accrue to PP&L customers. To the extent these programs are extended to new PP&L customers, reductions in uncollectible accounts cannot materialize. Those customers could only contribute to potential increased uncollectibles.

The Small Business Program is primarily targeted towards new customers. The benefits listed by PP&L for the Small Business Program are socially oriented and promise no potential cost savings to existing customers. Also, on the advice of counsel, the forgiving of demand charges raises the issue of rate discrimination.

Q. WHO INTENDS TO BENEFIT MOST BY THESE SOCIAL INITIATIVES BEING PROPOSED BY PP&L?

A. PP&L and ultimately PP&L's shareholders stand to gain the greatest benefit from these programs. This is readily apparent in the objectives and benefits listed by PP&L. Three of the four objectives listed by PP&L relate to demonstrating PP&L's commitment to addressing social concerns and enhancing PP&L's role and visibility in its service area communities. This is further illustrated in the top two benefits listed for the Build-A-Neighborhood and the Affordable Housing Programs. Those benefits are listed as (1) a highly visible demonstration of PP&L's social commitment and (2) improved relations with community organizations.

The enhancement of PP&L's corporate image provides negligible benefit to ratepayers.

Q. WOULD YOU COMMENT ON THE FUNDING OF THE THREE PROGRAMS YOU RECOMMEND DISALLOWING?

A. Yes. The funding of these social programs can be characterized as an attempt at extracting a forced contribution or even taxation of other ratepayers. Utilities certainly lack the statutory power of taxation and appropriation no matter how well intentioned the use of these funds.

Secondly, the Commission has consistently rejected the regulatory recovery of forced contributions. For example, the recovery of charitable contributions are routinely denied regulatory recovery. The funding of these social initiatives is no different than a charitable contribution and should be accorded the same treatment in determining rates.

Q. WHICH CUSTOMER CLASSES ARE BEING ASKED TO FUND THESE NEW PROGRAMS?

A. At present, PP&L is proposing that the $3,530,000 be funded by all customer classes.

Q. WHAT CONCERNS DO YOU HAVE REGARDING FUNDING OF THESE PROGRAMS IN FUTURE YEARS?

A. The electric industry is moving towards deregulation and open competition. Competitors of PP&L in this new environment will not be burdened by regulatory costs such as social programs. To compete, PP&L will need to shed these costs from the competitive customers. My concern is that these costs will become stranded and ultimately be shifted to those captive customers with no competitive alternatives. The expansion of social costs, at this time, does not appear to be compatible with the newly developing electric industry.

Q. WHY HAVEN'T YOU RECOMMENDED DISALLOWANCE OF THE COSTS RELATED TO THE KEEP WARM AND CARES EXTENSION PILOT?

A. The Keep Warm Program has the greatest potential to be cost beneficial. To the extent these weatherization and conservation measures are channelled toward customers who are currently experiencing or have experienced payment difficulties, savings may be realized in collection costs and uncollectible accounts.

Regarding the Cares Extension Pilot, the cost of this program is minimal and may prevent the growth of future uncollectible accounts by preventing a customer from becoming payment troubled.

Q. WHAT RECOMMENDATION DO YOU HAVE REGARDING THE KEEP WARM PROGRAM?

A. I recommend that the program be conducted as a three year pilot program. After three years, the Company would have an independent cost benefit analysis conducted to determine if the program is benefitting PP&L's ratepayers. Continuation of the program would be dependent upon the results of that evaluation.

In addition, PP&L should be held accountable for all funds received through rates for this program and be required to expend those funds. A report should be filed annually detailing receipts, expenditures and any accumulated excess funds.

CASH WORKING CAPITAL

Q. WHAT IS A CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC is the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses and the receipt of revenue in payment of services rendered. A lead lag study measures the differences in time between (1) the time services are rendered until payment of those services are received and (2) the time between when a utility has incurred an expense and the actual payment of the expense.

Q. WHAT IS THE COMPANY'S CLAIM FOR CWC?

A. The total net Company claim for CWC is a negative ($392,000) with a Pennsylvania jurisdictional claim of negative ($530,000). The five major components that comprise the Company's total CWC claim are as follows:

1.	Operation & Maintenance expense	$17,467
2.	Average Prepayments	11,041
3.	Accrued taxes	(284)
4.	Interest payments	(28,032)
5.	Preferred dividend payments	(722)
	Total cash working capital requirement	($530)

Q. WHAT IS YOUR PROPOSED ALLOWANCE FOR CASH WORKING CAPITAL?

A. I recommend a Pennsylvania jurisdictional negative CWC allowance of ($12,279,000). This represents a reduction of $11,749,000 to the Company's claim of ($530,000). OTS Exhibit No. 4, Schedule 9 summarizes my proposed allowance. I am recommending adjustments to two components of the total CWC claim; the claim related to O&M expenses and the funds invested in prepayments as shown in Column 3 of OTS Exhibit No. 4, Schedule 9. My total proposed allowance is as follows:

1.	Operation & Maintenance expense	$13,749
2.	Average Prepayments	3,010
3.	Accrued taxes	(284)
4.	Interest payments	(28,032)
5.	Preferred dividend payments	(722)
	Total cash working capital requirement	($12,279)

Q. WHAT IS THE COMPANY'S CLAIM FOR CWC RELATED TO O&M EXPENSES?

A. The Company has calculated a total CWC allowance of $20,238,000 related to O&M expense. The PPUC jurisdictional amount is $17,467,000 which is approximately 86.30% ($17,467,000/$20,238,000) of the total amount. The Company's claim is presented at Schedule C4, Page 2, Exhibit Future 1.

The Company's claim was derived by multiplying average daily O&M expenses of $4,306,000 times the net revenue lag of 4.7 days. The net revenue lag was determined based on an historic analysis of the relationship between the lag in receipt of revenues and the lag associated with the payment of expenses. The analysis was based on historic data for the twelve months ended September 30, 1994. The net revenue lag of 4.7 days is the difference between the average revenue lag of 35.6 days less the average expense lag of 30.9 days.

Q. WHAT IS YOUR RECOMMENDED ALLOWANCE FOR CWC RELATED TO O&M EXPENSE?

A. I recommend a PPUC jurisdictional allowance of $13,749,000 which represents a reduction of ($3,718,000) to the Company's claim. I have computed an average revenue lag of 35.0 days and a corresponding average expense lag of 31.3 days. The net revenue lag of 3.7 days (35.0 - 31.3) is a reduction of 1.2 days to the Company's claim. Reference OTS Exhibit No. 4, Schedule 10.

Q. HOW HAVE YOU ADJUSTED THE REVENUE LAG?

A. I have adjusted the revenue lag to correct a Company error. The revenue lag associated with 20 day due date customers was reported as 42 days. The 42 days is comprised of a 15 day lag for midpoint of service, a 3 day lag for billing and a 24 day collection lag.

As confirmed by the Company witness Mr. Bernini (Tr. 503), the correct collection lag should be 22 days and not 24 days. The correct total lag is now 40 days for the 20 day due date customers (Tr. 502).

When averaged with the revenue lags for the other revenue classes, the overall weighted revenue lag reduces from 35.6 to 35.0 days. The calculation is detailed at OTS Exhibit No. 4, Schedule 10. This issue will disappear upon recognition of this error in a future Company update.

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE O&M EXPENSE LAGS?

A. I am proposing adjustments to the lags for payroll and other miscellaneous O&M expenses.

Q. HOW HAS THE COMPANY COMPUTED THE LAG FOR PAYROLL EXPENSE?

A. The Company has divided payroll into two groupings, payroll-salary and payroll-hourly. For payroll salary the Company has calculated a lag of 11 days (OTS Exhibit No. 4, Schedule 10, Line 9, Column 2). The 11 days reflects the lag from midpoint of a 14 day payroll period ending Sunday to paydate the following Thursday. The payroll hourly lag of 16 days (OTS Exhibit No. 4, Schedule 10, Line 11, Column 2) reflects the lag from midpoint of a 14 day payroll period ending Sunday to paydate the second Tuesday thereafter.

These lags of 11 and 16 days were multiplied by the respective gross payrolls to determine the CWC needs for payroll expense.

Q. IN YOUR OPINION WHY IS THE COMPANY'S CWC CLAIM FOR PAYROLL OVERSTATED?

A. The Company lags gross payroll at 11 and 16 days respectively for each payroll grouping. However, at paydate, the Company only remits funds equal to net payroll. All federal income tax and FICA withholdings are deposited with an authorized bank at a later date. The Company has access and use of these funds beyond the actual paydate.

Q. HOW HAVE YOU ADJUSTED THE PAYROLL LAG?

A. The total payroll for payroll-salary is $216,316,000 and for payroll-hourly is $71,368,000. The Company was unable to breakdown gross payroll to net payroll (Tr. 515), therefore I first reduced gross payroll by 22.65% to determine the approximate withholdings for federal income tax and FICA. The 22.65% is comprised of a 7.65% withholding rate for FICA and a 15% federal income tax withholding rate. The 15% represents the first tax rate block for individuals. The Company very likely has some employees who, because of the number of exemptions claimed, have an effective federal withholding rate of less than 15%. It is also very likely that the Company has a greater number of employees whose withholdings greatly exceed 15%. Based on this calculation, I estimated payroll-salary and payroll-hourly withholdings to be $48,996,000 and $16,165,000 respectively. (Reference OTS Exhibit No. 4, Schedule 10, Lines 10 and 12).

These employee withholdings were then lagged at an additional 1 day for payroll-salary and 1 day for payroll-hourly. The withholdings for payroll salary is now lagged at 12 days and payroll-hourly at 17 days (OTS Exhibit No. 4, Schedule 10, Column 2, Lines 10 and 12).

Q. HOW DID YOU DETERMINE THE APPROPRIATE LAG FOR WITHHOLDINGS?

A. New federal deposit rules went into effect for the 1993 tax year. All depositors are classified as either monthly or bi-weekly depositors. Bi-weekly depositors are required to deposit their taxes by the Wednesday after payday, if payday falls on a Wednesday, Thursday or Friday. For all other paydays, the deposit is due by the Friday following payday. However, if the employer accumulated $100,000 or more in liability during a bi-weekly period the funds must be deposited on the first banking day after the $100,000 threshold is reached. This regulation would apply to PP&L

because annual withholdings would be $65,161,000 ($48,996,000 + 16,165,000) and definitely in excess of $100,000 at each paydate.

Q. WHAT IS THE COMPANY CLAIM LAG FOR OTHER O&M EXPENSES?

A. The Company has calculated a lag of 32 days for "Other" O&M expenses. Other O&M expenses are O&M expenses that did not fit into any of the specific cost elements listed on the lead/lag study. "Other" basically includes everything except payroll, benefits and purchased fuels. The Company computed an average lag of 32 days based on an analysis of invoices over a three month period ended July 31, 1994. The results of that analysis are presented at Company Attachment II-B-4, Page 30.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE LAG FOR OTHER O&M EXPENSE ITEMS?

A. I recommend a lag of 33 days for Other O&M expense items. (Reference OTS Exhibit No. 4, Schedule 10, Line 24, Column 2). This reflects an increase of one day to the Company's proposed lag of 32 days. OTS Exhibit No. 4, Schedules 12 and 13 detail my proposed adjustment.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT?

A. While spot checking various invoices related to materials and supplies, I questioned an invoice for $173,440 to Stamet, Inc. Included in this invoice was an amount of $170,000 for two Firth solids pumps. Upon further discovery the Company confirmed that these pumps had been capitalized and were included in ratebase (Tr. 519). I therefore reduced this invoice to $3,440 ($173,440 - $170,000) for purpose of the CWC calculation.

CWC is intended to determine the cash funds expended by the Company to cover the gap between payment of O&M expenses and the receipt of revenues from ratepayers. It specifically relates to O&M expenses not capital expenses. As an element of ratebase the Company is already earning a return on and return-off these capital expenses.

Q. WHAT IS THE COMPANY'S CLAIM FOR AVERAGE PREPAYMENTS?

A. The total Company claim is $12,824,000 with a PPUC jurisdictional claim of $11,041,000 (reference Schedule C-4, Page 3, Exhibit Future 1). The total claim is based on the 13 month average of six items; insurance nuclear, insurance other, NRC annual fees, PUC assessment, postage and Other. These claims are for items that the Company claims are prepayed. The monthly balances are the month end balances.

Q. WHAT IS YOUR RECOMMENDATION REGARDING AVERAGE PREPAYMENTS?

A. I recommend a total Company claim of $3,548,000 with a PPUC jurisdictional claim of $3,010,000 (reference OTS Exhibit No. 4, Schedule 11). I propose adjustments to the 13 month average balances for the PUC Annual Assessment, Insurance, Postage and Other category. In total I am proposing a reduction of ($8,031,000) to the Company's PPUC jurisdictional claim of $11,041,000 ($11,041,000 - $3,010,000). My adjustments to these four categories are summarized in the following table:

	Total Company Claim	OTS Allowance	Adjustment
	(000's)	(000's)	(000's)
Insurance Nuclear	$ 2,264	- 0 -	($2,264)
Insurance Other	3,283	- 0 -	($3,283)
NRC Annual Fee	172	172	- 0 -
PUC Assessment	379	1,782	1,403
Postage	156	- 0 -	(156)
Other	6,758	1,594	(5,164)
Total	$13,013	$3,548	($9,464)
	Pa. Jurisdictional @ 84.85%		($8,031)

Q. HOW HAVE YOU ADJUSTED THE AVERAGE PREPAYMENT CLAIM FOR PUC ANNUAL ASSESSMENTS?

A. In response to an OTS data request on the PUC assessment, the Company discovered an error in its original claim and submitted a revised calculation. (Reference OTS Cross Examination Exhibit No. 12, OTS-RE-28-D). The result is an increase in the original claim of $379,000 to $1,782,000.

Q. HOW HAVE YOU ADJUSTED THE CLAIM FOR POSTAGE AND INSURANCE?

A. I have totally eliminated the claims for postage and insurance in the amount of $156,000 and $5,547,000 ($2,264,000 + $3,283,000) respectively.

Q. WHAT IS THE BASIS FOR YOUR ELIMINATION OF THE THIRTEEN MONTH AVERAGE BALANCE FOR POSTAGE?

A. I have eliminated postage from prepayments because it is a duplicative claim. The Company has claimed CWC of $156,000 in prepayments for postage and approximately $127,000 for postage within the O&M CWC claim (reference Company Attachment II-B-4, Page 30).

Postage meters are replenished every 8 to 14 days. The meters are then utilized for a period of time until the postage reaches its minimum required supply. That minimum apparently is established by the Company and not the postal service (Tr. 517). Postage is no different than any other office supply in that the Company replenishes the supply before being exhausted. The period of service is short in nature. Postage expense certainly does not exhibit the characteristics of traditional prepayments such as the PUC annual assessments wherein the prepayments cover a service period up to twelve months.

Postage is traditionally handled in the lead/lag study and should remain there. The balances reflected as prepayments do not reflect any attempt by PP&L to determine a minimum postal supply balance but merely the balances at given points in time and is therefore duplicative of the claim within the lead/lag study. The lead/lag study compensates PP&L from the point of purchase to the midpoint of the service period which is adequate compensation to PP&L.

Q. WHY HAVE YOU ELIMINATED INSURANCE FROM THE PREPAYMENT BALANCES?

A. I have eliminated insurance prepayments in the amount of $5,547,000 for the same reason I have eliminated postage. The Company has claimed these identical insurance claims within their calculation of the CWC related to O&M expenses (Reference Attachment II-B-4, Pages 38-40). The CWC requirements related to insurance are traditionally claimed either as average prepayments or within the O&M CWC expense claim but to claim insurance costs in both represents a duplicate recovery. The CWC allowance requested within O&M expenses reimburses the Company for the period from the date the expense is paid until the expense is recovered from ratepayers. This reflects the maximum recovery that the Company is entitled to.

Q. WHAT IS THE NATURE OF "OTHER" PREPAYMENTS?

A. The other category includes basically four components. (Reference OTS Cross Examination Exhibit No. 12, OTS-RE-21D). The first component is prepaid rents for property used by PP&L. The second component is prepayments to the Susquehanna River Basin Commission for water purchases from the Cowanesque Reservoir. The third component is *prepayments to the Electric Power Research Institute and the final component* is prepayments to Chem-Nuclear Systems for low level waste disposal services at the Barnwell Facility.

Q. HAVE YOU REVIEWED THE MONTHLY BALANCES FOR OTHER PREPAYMENTS?

A. Yes. These balances are detailed at Company Schedule C-4, Page 3, Historic 1.

Q. WHY DOES THE BALANCE FOR MARCH 1994 GREATLY EXCEED ALL OTHER MONTHLY BALANCES?

A. The balance for March 1994 includes interest of $24,138,000 for long-term debt and $42,992,000 in cash dividend payments as prepayments. Because the payment date of April 1, 1994 fell on the Good Friday holiday and the commercial paper markets were closed, PP&L had to deposit these funds prior to April 1, 1994. They therefore are reflected in the March closing balance.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LONG-TERM DEBT INTEREST AND DIVIDEND PAYMENT?

A. The balances related to long-term debt interest and dividends should be removed from the prepayment balances. Ratepayers should not be required to provide working capital for below the line expense items. Furthermore, this was an unusual circumstance that will not occur during the future test year or in the near future.

Q. WHAT IS THE IMPACT OF REMOVING LONG-TERM DEBT INTEREST AND DIVIDENDS FROM OTHER PREPAYMENTS?

A. The average thirteen month balance is reduced from $6,758,000 to $1,594,000 or by $5,164,000.

Q. DOES YOUR RECOMMENDED NEGATIVE CWC ALLOWANCE OF ($12,279,000) REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenue, expense, taxes and rate base must be consistently brought together in the ALJ's Recommended Decision, and again in the Commission's Final Order. This process is known as "iteration" and it effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix A

Professional and Educational Background of
Charles T. Weakley, III

Education: A.A. in Accounting, Harrisburg Area Community College, 1973.

B.B.A. in Administration, Pennsylvania State University, 1975.

Graduate Studies in Operations Management, Pennsylvania State University, 1977.

Employment: Prior to accepting my position with the PUC, in the Bureau of Rates in February 1984, I was a Corporation Tax Officer with the Pennsylvania Department of Revenue.

I am a Certified Public Accountant, however, my license is currently inactive, since I am no longer in public practice. In addition, I am a Member of the Pennsylvania Institute of Certified Public Accountants and have three years of public accounting experience.

Testimony: I have testified and/or submitted testimony in the following proceedings:

PECO Rate Case, R-842590, R-850152 and R-891364

Penn Power Rate Case, R-842740, R-850267 and R-870732

Met-Ed Rate Case, R-842770 and R-00922314

Penelec Rate Case, R-842771

Testimony: Duquesne Light Rate Case, R-850021, R-860378 and R-870651

PECO - Gas Operations Rate Case, R-870629

Philadelphia Suburban Water Company Rate Case, R-870860 and R-891270

Peoples Natural Gas Rate Case, R-880961

Equitable Gas Rate Case, R-880971, R-901595 and R-912164

PECO-PGC No. 6, 1307(f) Proceeding, R-891290

T.W. Phillips Gas and Oil Co. PGC-90, R-891572

T.W. Phillips Gas and Oil Co. Rate Case, R-891566

Arrowhead Public Service Corporation Rate Case, R-891557

Peoples Natural Gas - PGC-90, 1307(f) Proceeding, R-901640

Peoples Natural Gas - PGC-91, 1307(f) Proceeding, R-911919

PECO-PGC No. 8, 1307(f) Proceeding, R-911976

West Penn Power - Petitions (CAAA, 1990) P-910511 and R-910512

Borough of Phoenixville - Rate Case, R-912038

Shenango Valley Water Company - R-912060 and R-00932798

Dallas Water Company, Inc. - R-00922326

Testimony:

Harvey's Lake Water Company, Inc. - R-00922327

Noxen Water Company, Inc. - R-00922328

Shavertown Water Company, Inc. - R-00922329

Pennsylvania Gas and Water Company (Spring Brook / Crystal Lake) R-00922404

Pennsylvania-American Water Company - R-00922428

Pennsylvania Gas and Water Company (Scranton) R-00922482

National Fuel Gas Distribution Corporation - R-00932548

Lemont Water Company, Rate Case, R-00932673

The Peoples Natural Gas Company, Rate Case, R-00932866

The Peoples Natural Gas Company, 1994-1307(f), R-00943028, C-945601

Equitable Gas Company - R-00943246

Exh
OTS ~~Statement~~ No. 4
Dated: April 14, 1995

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

Direct Testimony

of

Charles T. Weakley, III

Concerning:

Operating and Maintenance Expenses
Rate Base

OTS Exhibit No. 4
Schedule No. 1

Pennsylvania Power & Light Company
Docket No. R-00943271

POSTRETIREMENT BENEFITS (SFAS 106)

OTS RECOMMENDED ADJUSTMENT TO REJECT THE RECOVERY OF THE DEFERRED EXPENSES FOR SFAS 106 BENEFIT COSTS. PP&L HAS REQUESTED A 17.3 YEAR AMORTIZATION OF THE $31,095,000 DEFERRED ASSET OR A $1,797,000 EXPENSE CLAIM ON A TOTAL COMPANY BASIS. MY ADJUSTMENT WILL REDUCE O&M EXPENSES ON A PUC JURISDICTIONAL BASIS BY $1,561,000.

SFAS 106 DEFERRED ASSET	$ 31,095,000	
DIVIDED BY 17.3 YEARS	17.3	
EXPENSE CLAIM ON A TOTAL COMPANY BASIS	$ 1,797,000	(A)
TIMES THE PA JURISDICTIONAL ALLOCATION PERCENTAGE	86.8421%	(B)
RECOMMENDED REDUCTION TO O&M EXPENSE	$ 1,561,000	

(A) Reference PP&L Exhibit Future 1, Schedule D-6.
(B) Reference OTS Cross Examination Exhibit No. 11.

OTS Exhibit No. 4
Schedule No. 2

Pennsylvania Power & Light Company
Docket No. R-00943271

PENSION EXPENSE

OTS RECOMMENDED ADJUSTMENT TO DISALLOW THE SFAS 87 PENSION BENEFIT CLAIM. PP&L HAS CLAIMED $17,898,000 OF SFAS 87 PENSION COSTS IN THE FUTURE TEST YEAR ON A TOTAL COMPANY BASIS. MY ADJUSTMENT WILL REDUCE ON A PA. JURISDICTIONAL BASIS, O&M EXPENSES BY $10,224,000 AND RATE BASE BY $5,273,000.

SFAS 87 PENSION BENEFIT	$ 17,898,000	(A)
PENSION BENEFIT TO EXPENSE TOTAL COMPANY	$ 11,808,000	(A)
PENSION BENEFIT TO RATE BASE TOTAL COMPANY	$ 6,090,000	(B)
PUC JURISDICTIONAL AMOUNT TO EXPENSE	$ 10,224,000	(A)
PUC JURISDICTIONAL AMOUNT TO RATE BASE	$ 5,273,000	(C)

(A) Reference OTS Exhibit No. 4, Schedule No. 7.
(B) $17,898,000 - $11,808,000 = $6,090,000.
(C) ($10,224,000 / $11,808,000) x $6,090,000 = $5,273,000.

OTS Exhibit No. 4
Schedule No. 3

Pennsylvania Power & Light Company
Docket No. R-00943271

ENVIRONMENTAL REMEDIATION PROGRAM EXPENSE

OTS RECOMMENDED ADJUSTMENT TO REDUCE THE COMPANY'S CLAIM FOR ENVIRONMENTAL REMEDIATION PROGRAM EXPENSE. PP&L HAS CLAIMED $5,400,000 OF REMEDIATION EXPENSES IN THE FUTURE TEST YEAR ON A TOTAL COMPANY BASIS. MY ADJUSTMENT WILL REDUCE O&M EXPENSES BY $1,304,000 ON A PUC JURISDICTIONAL BASIS.

REMEDIATION EXPENSE CLAIM	$ 5,400,000	(A)
OTS RECOMMENDED LEVEL	$ 3,800,000	(B)
REDUCTION ON TOTAL COMPANY	$1,600,000	(C)
PUC JURISDICTIONAL ALLOCATION	81.4815%	(D)
RECOMMENDED DISALLOWANCE	$ 1,304,000	(E)

(A) Reference PP&L Exhibit Future 1, Schedule D-16.
(B) Reference OTS Cross Examination Exhibit 11.
$316,000 x 12 = $3,800,000.
(C) A - B
(D) Reference PP&L Exhibit JMK 2, pages 21 and 42.
1100 / 1350 = 81.4815%
(E) C * D

OTS Exhibit No. 4
Schedule No. 4

Pennsylvania Power & Light Company
Docket No. R-00943271

RATE CASE EXPENSE

OTS RECOMMENDED ADJUSTMENT TO REDUCE THE COMPANY'S CLAIM FOR RATE CASE EXPENSE. PP&L HAS CLAIMED $746,000 OF RATE CASE EXPENSES IN THE FUTURE TEST YEAR BASED ON A TWO YEAR NORMALIZATION. MY ADJUSTMENT WILL REDUCE O&M EXPENSES BY $373,000.

ESTIMATED RATE CASE EXPENSE	$ 1,491,000	(A)
COMPANY'S CLAIM	$ 746,000	(B)
OTS RECOMMENDED LEVEL	$ 373,000	(C)
RECOMMENDED DISALLOWANCE	$ 373,000	(D)

(A) Reference PP&L Exhibit Future 1, Schedule D-7.
(B) Reference PP&L Exhibit Future 1, Schedule D-7.
$1,491,000 / 2 = $746,000.
(C) $1,491,000 / 4 = $373,000.
(D) B - C.

OTS Exhibit No. 4
Schedule No. 5

Pennsylvania Power & Light Company
Docket No. R-00943271

RATE CASE EXPENSE

OTS ANALYSIS OF RATE CASE FILING INTERVALS

DOCKET NO.	FILING DATE	FILING INTERVAL
R.I.D. 251	3-31-75	
		61 MONTHS
R-80031114	4-29-80	
		16 MONTHS
R-811636	8-28-81	
		15 MONTHS
R-822169	11-22-82	
		20 MONTHS
R-842651	7-27-84	
		125 MONTHS
R-00943271	12-30-94	
	AVERAGE	48 MONTHS

OTS EXHIBIT No. 4
Schedule No. 6

R. J. Bemini

Pennsylvania Power & Light Company
Response to Interrogatories of the
Office of Consumer Advocate, Set IV
Dated February 1, 1995
Docket No. R-00943271

Q.72. Please show the derivation and provide a breakdown by year of the SFAS No. 106 expenses which PP&L claims it would have deferred under the PUC Order at Docket No. P-920635.

A.72. The requested data is provided in Attachment 1.

Attachment 1

OTS Exhibit No. 4
Schedule No. 6

PENNSYLVANIA POWER & LIGHT COMPANY
PUC JURISDICTIONAL PORTION OF FAS 106 COSTS CHARGED TO EXPENSE
UNDER COMMONWEALTH COURT REVERSAL OF PUC ORDER PERMITTING DEFERRAL

	Amount	
Balance as of December 31, 1993	$10,769,913	
January - September 1994	8,710,556	
Balance at September 30, 1994	$19,480,469	
12 Months Ended September 30, 1995	11,614,080	(a)
Balance at September 30, 1995	$31,094,549	

(a) $8,710,556 (Jan. - Sept. 1994) ÷ 9 mos. x 12 mos. = $11,614,080

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Trial Staff
Dated January 13, 1995
Docket No. R-00943271

Q. OTS-RE-4D. Reference PP&L Exhibit II-D-10 and provide the following related to pension expense:

A. Provide the claimed pension expense amounts for the historic and future test year.

B. Provide a copy of the latest actuarial report for pensions which shows the funding requirements and amounts under ERISA and the IRC.

C. Please explain the basis (ERISA or SFAS 87) of the claim for pension expense.

D. An explanation of the Company's funding policy.

E. The annual amount and dates of the actual cash contributions made to the pension fund over the last three years or the date and amount of the last required contribution.

A. OTS-RE-4D. The following responses reference Exhibit II-D-10.

A. The following is the claimed pension expense for the Future and Historic Test Years:

	Future Test Year	Historical Test Year
	(M$)	
Pension Benefit	$17,898	$16,804
Pension Benefit to Expense	11,808	11,385
PUC Jurisdictional Amount	10,224	9,858

B. A copy of the latest actuarial report, prepared by Towers-Perrin, is provided as Attachment 1. Because this document is voluminous, copies are being provided only to the Pennsylvania Public Utility Commission's (PUC) Office of Trial Staff. Copies will be provided to other parties upon request.

C. The Company is claiming the SFAS 87 Net Periodic Pension Cost.

D. Funding is based upon actuarially determined computations that take into account the amount deductible for income tax purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974. In general, the Company's funding policy has been to contribute to the Retirement Plan, annually, an amount equal to the Net Periodic Pension Cost. However, since 1988, the maximum allowable and minimum required contribution level has been zero. No contributions have been permitted, and an accrued pension cost has been recorded on the Company's balance sheet. Therefore, when permitted in the future, the Company's funding policy will be to contribute not only the annual Net Periodic Pension Cost but also an amount sufficient to eliminate, over time, the accrued pension cost. Current actuarial projections indicate that contributions will be permitted in 1996.

E. The last contribution was made on June 3, 1988 in the amount of $18,472,405.

OTS Exhibit No. 4
Schedule 8

Pennsylvania Power & Light Company

OTPP UNCOLLECTIBLE ACCOUNTS EXPENSE

Per the Office of Trial Staff

Company Claim:

Average revenue shortfall	
2,000 customers @ $161 =	$322,000
Average Arrearage Forgiveness	
2,000 customers @ $194 =	388,000
Total Claim	$710,000
Less OTS Proposed Reduction:	
LIHEAP Grants at 30 % of	
the 2,000 customers @ $233 =	140,000
OTS Proposed Allowance	$570,000

OTS Exhibit No. 4
Schedule 9

Pennsylvania Power & Light Company

Cash Working Capital
Per the Office of Trial Staff
As of September 30, 1994
(Thousands of Dollars)

Line No.	Description	PPUC Jurisdictional Company Claim (1)	PPUC Jurisdictional OTS Allowance (2)	OTS Proposed Reduction (3 = 2-1)
1	Operation and maintenance	$17,467	$13,749 (a)	($3,718)
2	Average Prepayments	11,041	3,010 (b)	($8,031)
3	Accrued taxes	(284)	(284)	$0
4	Interest payments	(28,032)	(28,032)	$0
5	Preferred dividend payments	(722)	(722)	$0
6	Total cash working capital requirement	($530)	($12,279)	($11,749)

(a) Reference Ots Exhibit No. 4, Schedule 10.

(b) Reference Ots Exhibit No. 4, Schedule 11.

Pennsylvania Power & Light Company

Working Capital Required for Operation and Maintenance Expenses
Per the Office of Trial Staff
As of September 30, 1995
(Thousands of Dollars)

Line No.	Description	Amount	Avg. Days	Weighted Amount
	Average Lag in Receipt of Operating Revenue			
1	Revenue from 15-day due date customers	$1,228,343	35 (a)	$42,992,005
2	Revenue from 20-day due date customers	953,979	40 (a)	38,159,160
3	Revenue from 30-day due date customers	209,584	39 (a)	8,173,776
4	Interchange delivered	74,326	35	2,601,410
5	Revenue from UGI	26,356	20	527,120
6	Revenue from Power Contracts	296,990	17	5,048,830
7	Total Revenue (D-3)	$2,789,578	35.0	$97,502,301
	Average Lag in Payment of Operation and Maintenance Expense			
9	Payroll - salary	$167,320	11	$1,840,520
10	Payroll - withholding	48,996	12 (b)	587,952
11	Payroll - hourly	55,203	16	883,248
12	Payroll - withholding	16,165	17 (b)	274,805
13	Employee benefits	64,720	37	2,394,640
14	Bituminous coal	241,427	36	8,691,372
15	Anthracite	10,051	37	371,887
16	Coal freight bills	77,349	23	1,779,027
17	Petroleum coke	2,621	39	102,219
18	Oil	9,039	15	135,585
19	Martins Creek Units 3 and 4 oil	61,917	24	1,486,008
20	Martins Creek Units 3 and 4 oil transportation	14,903	41	611,023
21	Interchange Purchased	42,178	35	1,476,230
22	Purchased power - firm	10,222	32	327,104
23	Purchased power - surplus	260,146	46	11,966,716
24	Other	523,011	33 (c)	17,259,363
	Total pro forma O&M expense	$1,605,268	31.3	$50,187,699
25	Average lag in receipt of revenue			35.0
26	Average lag in payment of operating expense			31.3
27	Average lag in days between payment of operating expense and receipt of revenue (line 24 - line 25)			3.7
28	Operating expense per day (FTY O&M $1,571,676 / 365 days)			$4,306
29	Working capital requirement (line 27 x line 26)			$15,932
30	**PPUC Jurisdictional (86.30%)**			**$13,749**

	Customer Due Date		
	15 Days	20 Days	30 Days
(a) Midpoint of 30-day service period	15 days	15 days	15 days
Lag between meter reading and billing date	3 days	3 days	3 days
Lag between billing date and payment date	17 days	22 days	21 days
	35 days	40 days	39 days

(b) Increased by one day.
(c) Reference Ots Exhibit No. 4, Schedule 12.

OTS Exhibit No. 4
Schedule 11

Pennsylvania Power & Light Company

Average Prepayments
Per the Office of Trial Staff
As of September 30, 1995
(Thousands of Dollars)

Line No.	Month	Nuclear	Insurance Other	NRC Annual Fee	PUC Annual Assessment (a)	Postage	Other (b)	Total
1	September 1994	$0	$0	$0	$2,321	$0	$2,043	$4,364
2	October	0	0	0	2,063	0	2,756	$4,819
3	November	0	0	462	1,805	0	1,829	$4,096
4	December	0	0	0	1,547	0	1,518	$3,065
5	January 1995	0	0	0	1,290	0	2,231	$3,521
6	February	0	0	444	1,032	0	1,292	$2,768
7	March	0	0	0	774	0	984	$1,758
8	April	0	0	907	516	0	2,034	$3,457
9	May	0	0	426	258	0	1,121	$1,805
10	June	0	0	0	3,309	0	209	$3,518
11	July	0	0	0	3,033	0	1,135	$4,168
12	August	0	0	0	2,758	0	2,143	$4,901
13	September	0	0	0	2,461	0	1,428	$3,889
14	Total Payments	$0	$0	$2,239	$23,167	$0	$20,723	$46,129
15	Monthly Average	$0	$0	$172	$1,782	$0	$1,594	$3,548
16	**PPUC Jurisdictional**		84.85%					$3,010

(a) Reference Ots Cross Examination Exhibit No. 12.

(b) March 1994 has been reduced by $24,138 for long-term interest & $42,992 for cash dividends.

OTS Exhibit No. 4
Schedule 12

Pennsylvania Power & Light Company

Lag in Payment of Other Expenses
3 Months Ended July 31, 1994
Per the Office of Trial Staff

Location	Amount	Days Lag		Weighted Amount
Employee Expenses	$2,174,023.11	1.00		$2,174,023
Materials & Supplies	9,833,406.62	31.13	(a)	306,116,425
Printing & Office Supplies	1,253,552.42	11.41		14,303,033
Contract Tree & Bush Control	4,089,585.15	43.80		179,123,830
Work by Outsiders	25,824,968.30	57.24		1,478,221,185
Services	10,430,773.44	38.15		397,934,007
Postage	1,175,153.52	(4.00)		(4,700,614)
Telephone & Leased Wires	1,612,532.43	33.30		53,697,330
Rents	7,738,913.02	17.89		138,449,154
Insurance	3,135,850.16	(133.92)		(419,953,053)
Keystone (Excluding Fuel)	1,218,218.00	(4.00)		(4,872,872)
Conemaugh (Excluding Fuel)	1,214,809.00	(4.00)		(4,859,236)
Disposal of Spent Nuclear Fuel	2,885,649.00	74.00		213,538,026
Decommissioning Costs	1,798,677.00	16.33		29,372,395
Nuclear Fuel Financing Costs	1,592,582.00	70.00		111,480,740
Leased Fuel				
Total	$75,978,693.17	33.00		$2,490,024,373
Weighted Average Lag = Total Weighted Amount / Total Amount		33.00		Days

(a) Reference Ots Exhibit No. 4, Schedule 13.

Pennsylvania Power & Light Company

Lag in Payment of Materials & Supplies
3 Months Ended July 31, 1994
Per the Office of Trial Staff

Vendor	Voucher Number	Payment Date	Mid-point of Service Date	Amount (A)	Days Lag (B)	Weighted Amount (C) = (A) X (B)
Raub Supply Co.	727314	5/31/94	5/11/94	$2,625.00	20.00	$52,500
Stamet Inc. *	730051	5/10/94	4/27/94	3,440.00	13.00	44,720.00
Graver Chemical	730932	5/31/94	5/3/94	172,800.00	28.00	4,838,400.00
Hanson Office Products	732097	5/12/94	8/25/93	230.40	260.00	59,904.00
New Pig Corp	735248	6/8/94	5/11/94	985.74	28.00	27,600.72
Conestoga Fuels Inc	738424	5/20/94	3/10/94	21,008.52	71.00	1,491,604.92
Emery Worldwide	741918	5/25/94	4/27/94	158.52	28.00	4,438.56
US Filter/IWT	743393	6/20/94	5/24/94	58,500.00	27.00	1,579,500.00
Strathmeyer Forests Inc	746163	6/6/94	5/10/94	17,242.24	27.00	465,540.48
General Electric	750064	6/30/94	6/1/94	7,562.00	29.00	219,298.00
P A Peters Inc	755975	6/17/94	5/18/94	1,279.08	30.00	38,372.40
Airco	762278	7/14/94	5/21/94	1,214.45	54.00	65,580.30
C&D Charter Power Sys	769589	7/22/94	6/22/94	9,269.00	30.00	278,070.00
Basic Engineers Inc	770760	8/1/94	7/1/94	3,903.80	31.00	121,017.80
Abrasion Resistant Specia	772665	7/12/94	6/9/94	3,368.00	33.00	111,144.00
NSS Numanco	774469	7/28/94	6/21/94	9,110.68	37.00	337,095.16
Powertech Engineers Inc	781108	8/12/94	7/14/94	204.94	29.00	5,943.26
	Total			$312,902.37		$9,740,729.60

Weighted Average Lag C/A = 31.13 Days

* Total invoice of $173,440 less $170,000 related to pumps.

R. J. Bernini

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Trial Staff
Dated January 13, 1995
Docket No. R-00943271

Q. OTS-RE-37D. Provide the following information, for the test year and the three previous years, by customer class:

A. Total gross write-offs of uncollectible accounts.

B. Total revenues of uncollectible accounts.

C. Net write-offs of uncollectible accounts.

D. Total revenues.

A. OTS-RE-37D. Although information is available on an individual customer basis, the Company reports information on uncollectible accounts by Residential and Non-Residential customer classifications.

A. See Attachment 1

B. Total revenues of uncollectible accounts are the same as total gross write-offs provided in Attachment 1.

C. See Attachment 2

D. See Attachment 3

TOTAL GROSS WRITE-OFFS OF UNCOLLECTIBLE ACCOUNTS

Twelve months ended	Total	Residential	Non-residential
September 30, 1995 (projected)	$19,493,552	$17,227,468	$2,266,084
September 30, 1994	$20,990,131	$18,550,073	$2,440,058
September 30, 1993	$21,189,915	$18,317,743	$2,872,172
September 30, 1992	$21,280,439	$18,249,008	$3,031,431

NET WRITE-OFFS OF UNCOLLECTIBLE ACCOUNTS

Twelve months ended	Total	Residential	Non-residential
September 30, 1995 (projected)	$15,566,499	$13,773,008	$1,793,491
September 30, 1994	$16,761,586	$14,830,403	$1,931,183
September 30, 1993	$16,361,087	$14,636,220	$1,724,867
September 30, 1992	$18,306,755	$15,726,630	$2,580,125

TOTAL ELECTRIC REVENUES
(Thousands of dollars)

Twelve months ended	Total	Residential	Non-residential
September 30, 1995 (projected)	$2,715,478	$919,237	$1,796,241
September 30, 1994	$2,684,010	$939,511	$1,744,499
September 30, 1993	$2,679,895	$909,784	$1,770,111
September 30, 1992	$2,653,407	$865,959	$1,787,448

PENNSYLVANIA POWER & LIGHT COMPANY
DOCKET NO. R-00943271

OTS CALCULATED REVENUE REQUIREMENT ASSOCIATED WITH THE EXCESS CAPACITY RATE BASE ADJUSTMENT RECOMMENDED BY OTS WITNESS METRO (OTS STATEMENT NO. 5).

Rate Base Reduction	$239,474,000
OTS Rate of Return	.0914
Income Available	$ 21,887,924
Less Tax Increase (a)	- 3,742,215
Net Income Available	$ 18,145,709
Revenue Factor	÷ .549058
Net Revenue Affect	$ 33,048,802

(a)	Rate Base Reduction	$239,474,000
	OTS Weighted Debt Cost	.037080
	Interest Expense	$ 8,879,696
	Tax Factor	.421435
	Tax Increase	$ 3,742,215

PPLICA St. 9
+ Exs
LK-1 thru LK-5
SJM
5-2-95
NVS
R-943271

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

Air Products and Chemicals, Inc.
Alumax Mill Products, Inc.
Appleton Papers Inc.
Armstrong World Industries, Inc.
BOC Gases
CertainTeed Corporation
Chamberlain Manufacturing Corporation
Cressona Aluminum Company
ESSROC Materials, Inc.
Grinnell Corporation
Hercules Cement Company
Hershey Foods Corporation
International Paper Company
Lafarge Whitehall Cement
Liquid Carbonic Industries
Magee Carpet Company
M&M/Mars, Inc.
Praxair, Inc.
R. R. Donnelley & Sons
The Stroh Brewery Company
Thomson Consumer Electronics, Inc.
Victaulic Company of America

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), Suite 475, 35 Glenlake Parkway, Atlanta, Georgia 30328.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Bachelor of Business Administration in Accounting from the University of Toledo. I also received a Master of Business Administration from the University of Toledo. I am a Certified Management Accountant ("CMA") and a Certified Public Accountant ("CPA").

Since 1986, I have held various positions with Kennedy and Associates. I specialize in revenue requirements analyses, taxes, the evaluation of rate and financial impacts of traditional and non-traditional ratemaking, and other utility strategic, operational, financial, and accounting issues.

From 1983 to 1986, I held various positions with the consulting group at Energy Management Associates. I specialized in utility finance, utility accounting issues, and computer financial modeling. I also directed consulting and software projects utilizing PROSCREEN II and ACUMEN proprietary software products to support utility rate case filings, budgets, internal management and external reporting, and strategic and financial analyses.

From 1976 to 1983, I held various positions with The Toledo Edison Company in the Accounting and Corporate Planning Divisions. From 1980 to 1983, I was responsible for the Company's financial modeling and financial evaluation of the Company's strategic plans. In addition, I was responsible for the preparation of the capital budget, various forecast filings with regulatory agencies, and assistance in rate and other strategy formulation. I utilized the strategic planning model PROSCREEN II, the production costing model, PROMOD III, and other software products to evaluate capacity swaps, sales, sale/leasebacks, cancellations, write-offs, unit power sales, and long term system sales, among other strategic options. From 1976 to 1980, I held various other positions in the Budget and Accounting Reports, Property Accounting, Tax Accounting, and Internal Audit sections of the Accounting Division.

I have appeared as an expert witness on accounting, finance, and planning issues before regulatory commissions and courts in numerous states on nearly one hundred occasions. In addition, I have developed and presented papers at various industry conferences on utility rate, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit ___ (LK-1).

Q. Please describe the firm of Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric, gas, and telecommunications utilities industries. The firm provides expertise in system planning, load forecasting, financial analysis, revenue requirements, cost of service, and rate design. Clients include state agencies and industrial electricity and gas consumers.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the PP&L Industrial Customer Alliance ("PPLICA"), a group of large industrial customers of Pennsylvania Power & Light Company ("PP&L").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the components of the test year revenue requirement requested by PP&L, to make recommendations with respect to the recovery of certain costs, to quantify the effects on the test year revenue requirement of those recommendations, and to summarize the total adjustments to the Company's requested revenue requirement recommended by the PP&L Industrial Customer Alliance.

Q. Please summarize your testimony.

A. I recommend that the Commission reject or otherwise modify numerous components of the Company's requested test year revenue requirement. My recommendations as well as the related reductions to the revenue requirement are as follows:

- **Reject current test year recovery of future fossil dismantling costs ($45.022 million).**

- **Reject shorter depreciation lives for certain fossil generating facilities ($19.222 million).**

- **Reject the "levelization" of Susquehanna 1 and 2 modified sinking fund depreciation ($30.626 million).**

- **Modify the nuclear decommissioning annuity accruals to reflect a higher rate of return and to establish an earnings performance standard ($19.927 million).**

- **Reduce the gross deferred Voluntary Early Retirement Program ("VERP") costs to reflect nine months of savings and extend the amortization period for the net costs to ten years ($9.564 million).**

- **Reject the amortization of an imputed SFAS No. 106 deferral balance ($1.894 million).**

I have also quantified the effect of Mr. Baudino's rate of return recommendations. Mr. Baudino's recommendation to utilize a 10.85% return on common equity reduces the Company's requested revenue requirement by $84.687 million. Mr. Baudino's recommendation to utilize the September 30, 1994 actual capital structure reduces the Company's requested revenue requirement by an additional $5.017 million.

Finally, the effects of the preceding recommendations would be the same whether applied against the Company's requested total revenue requirement or its requested deficiency. However, Mr. Baron, on behalf of the PPLICA, has identified an error in the Company's computation of the deficiency. Thus, if the deficiency is utilized as the starting point for revenue requirement adjustments, then the Company's requested $261.635 million should first be reduced by $21.790 million to $239.845 million to correct for its error.

In the aggregate, PPLICA witnesses recommend a reduction of at least $215.959 million to the Company's $239.845 corrected revenue requirement request, recognizing that there will likely be other revenue requirement issues raised by other parties that may also be supported by PPLICA.

II. FOSSIL DISMANTLING

Q. Please describe the Company's request to recover projected fossil dismantling costs.

A. The Company has inflated its requested revenue requirement by $45.022 million to recover on an annuity basis the costs it projects it will incur when it removes its fossil units from service. The amounts included by the Company in its proposed cost of service are $52.818 million total Company and $43.041 million PPUC jurisdiction.

The Company has mimicked the methodology and certain of the assumptions it utilized to develop its request for recovery of nuclear decommissioning costs. PP&L commissioned TLG to perform a fossil decommissioning study similar in concept to the study TLG was commissioned to perform for the Susquehanna units. The Company then utilized assumptions similar to those employed for nuclear decommissioning to project the costs into the future years and to annuitize the costs based upon the establishment of a "fossil dismantlement" fund earning the same after tax rate of return.

Q. Has the Company provided testimony describing the rationale underlying its request for current test year recovery of projected fossil dismantling costs?

A. No. Mr. Bernini's testimony briefly describes only the Company's ratemaking request and the Company's proposed funding treatment if its ratemaking request is approved. Mr. Bernini provides no rationale in support of the Company's request. Mr. LaGuardia's testimony presents only the results of the fossil dismantling studies commissioned by PP&L and performed by TLG Services. There is no other testimony that directly addresses the request for recovery of fossil dismantling costs.

Q. Why should the Commission reject the Company's request for future projected fossil dismantling costs?

A. First, no rationale whatsoever has been offered by the Company in support of its request. Thus, the Commission has been offered no reason to allow recovery of this cost.

Second, this is an unnecessary and purely discretionary cost of service in the current test year. The Commission is under no legal or accounting mandate to prematurely recognize costs that may be incurred decades into the future.

Third, the Commission already has a mechanism in place to recover the costs of fossil dismantling if and when the fossil facilities are actually removed from service. Historically, the Commission has allowed recovery of the five year average of net negative salvage. Fossil dismantling is simply another name for net negative salvage associated with fossil generating facilities. The Company's cost of service includes the cost of $20.2 million in net negative salvage based upon the five year average methodology.

Fourth, the projections are speculative. The cost is not known and measurable and inherently lacks the objectivity associated with actual expenditures. The projections depend upon numerous physical assumptions. One assumption is that there will be no life extensions. Yet, Pennsylvania statutes require unit upgrades and life extensions for coal facilities where economically feasible. Another assumption is that there will be no changes to existing dismantling technology. That is highly unlikely.

To further illustrate the speculative nature of the projections, contrast the $628.5 million total cost of future fossil dismantling projected by the Company to the negative net $0.064 million it has actually spent on fossil dismantling since 1951. The reality is that over the 45-year period, the actual total salvage proceeds of $1.017 million exceeded the actual $0.953 million decommissioning costs. I have attached as my Exhibit___(LK-2) an annual history of the Company's actual fossil dismantling costs.

Fifth, there is actually a penalty and an increased cost of service resulting from the Company's request. The Company's annuity accrual assumes that it will fund a fossil dismantling trust fund. However, unlike contributions to the nuclear decommissioning trust fund, contributions to a fossil dismantling trust fund are not tax deductible until the dismantling costs are actually incurred. Assuming a federal income tax rate of 35%, no more than 65% of the funds prematurely paid by ratepayers could possibly earn a rate of return to apply to any future costs.

In addition, the after tax return for fossil would be lower than assumed by the Company, assuming an equivalent before tax return between nuclear and fossil. The Company assumed an after tax return of 5.50%, equivalent to the rate of return it assumed on the nuclear decommissioning trust fund. Even if the rate of return assumed by the Company were valid, the federal income rate for nuclear decommissioning trust fund earnings is 20% compared to the full 35% for any fossil dismantlement trust fund. Mathematically, the after tax return on a fossil dismantlement fund would be lower than on the nuclear decommissioning fund.

Further, the Company's request is clearly inequitable and lacks any legitimate economic rationale. The Company has requested an after tax return on its rate base of 10.23% in this proceeding. The revenue requirement effect of that request is 15.78% after gross-up for income taxes. Contrast the 15.78% before tax return sought from ratepayers by the Company on <u>its</u> investment with the 6.88% before tax (assuming a 20% tax rate) offered by the Company to ratepayers for <u>their</u> investment. That is a glaring differential.

Finally, the premature recovery of projected dismantlement costs has been repeatedly rejected by the Commission. Instead, the Commission's practice has been to allow recovery of the five year average of actual net negative salvage. Most recently, the Commission considered the request of West Penn Power for current test year recovery of future dismantlement costs. With respect to West Penn Power's request, the Commission stated:

> **"Consequently, we reject the Company's claim because of its uncertain and speculative nature and because this claim is patently counter to existing precedent."** (West Penn Power Opinion and Order Docket No. R-00942986, entered December 29, 1994, page 63.)

III. SHORTER FOSSIL PLANT DEPRECIABLE LIVES

Q. **Please describe the Company's request to recover the costs of <u>shortening</u> the depreciable lives of certain fossil plant.**

A. The Company has requested an incremental revenue requirement of $19.222 million in order to shorten the lives for depreciation accounting purposes of certain fossil generating units at Holtwood (Unit 17), Martins Creek (Units 1 & 2) and Sunbury (Units 1, 2, 3 and 4) by six to twelve years. The amounts included by the Company in its cost of service are $20.476 million total Company and $16.687 million PPUC jurisdiction.

The cost of service amounts were obtained from the Company's response to discovery (PP&L Industrial Customer Alliance, Set IV, Q.1) which I have replicated as my Exhibit _____ (LK-3). The computation of the incremental revenue requirement amounts is also detailed on my Exhibit ___ (LK-3).

Q. **Did the Company also request to <u>extend</u> the depreciable lives of certain other fossil plant?**

A. Yes. The Company's request was to shorten the depreciable lives of certain fossil plant and to extend the lives of certain other fossil plant. Although the Company's request was presented on a "net" basis, I recommend that the Commission separate the two components. I recommend that the Commission reject the Company's proposal to shorten the depreciable lives of certain fossil plant and accept its proposal to lengthen the depreciable lives of certain other fossil plant.

Q. Why should the Commission reject the Company's request to shorten the depreciable lives of the fossil generating plant?

A. The first and most compelling reason is that neither the Company nor the Commission has any economic basis or any quantified data or analyses that shortening the depreciable lives for these units is necessary or even appropriate. In fact, the exact opposite may well be the optimal economic option. Although the studies provided by the Company were not prepared for the purpose of comparing and optimizing the economics of alternative retirement dates for these fossil generating units, they conclude that continued operation of the units is both prudent and economical well beyond their current depreciable lives.

Second, there is no harm to the Company if the depreciable lives are not shortened in this proceeding. If indeed appropriate studies are performed by the Company in the future and the Commission agrees that the optimal economic option is to retire specific units on an earlier schedule, then the depreciable lives and the depreciation expense can be adjusted at that time.

Q. Please describe in more detail the studies relied upon by the Company in its request to accelerate the retirement dates of certain fossil facilities.

A. The Company was requested to provide all studies relied upon to revise its projected retirement dates for the generating facilities identified on Exhibit DAK-4 (PP&L Industrial Customer Alliance, Set II, Q. 13 and Office of Consumer Advocate, Set IV, Q. 86). In addition, the Company was requested to provide any studies that examined the cost effectiveness of life extension compared to retirement/replacement (Office of Consumer Advocate, Set IV, Q. 85).

In response to these requests, the Company provided its Five-Year Upgrade Plan for Coal-Fired Generation previously filed with the Commission in accordance with Pennsylvania statutory requirements. That study was not prepared for the purpose of optimizing the timing of retirements of generating capacity but rather to respond to regulations that "require utilities to uprate their electric power production by upgrading the capability to use coal in existing coal-fueled plants where economically feasible and where the uprate is beneficial to ratepayers" in order to promote the use of coal.

Nevertheless, that study concluded that continued operation of the Holtwood, Martins Creek, and Sunbury units was both prudent and economical "through at least 2013."

That conclusion is in direct opposition to the Company's proposed acceleration of the "deactivation dates" for these units to the year 2003.

In addition, the Company provided the Executive Summary of a report prepared in 1994 for the Keystone-Conemaugh Owners' Committee titled "Keystone Integrated Fuel Supply and Environmental Compliance Strategy Evaluation." It also provided selected pages from a report prepared in 1991 for the Keystone-Conemaugh Owners Committee titled "Conemaugh Station Clean Air Act Compliance Strategy." Similar to the other studies, these reports were not prepared for the purpose of optimizing the timing of retirements of the Company's generating capacity. Instead, these reports were prepared to address the Company's fuel selection and environmental compliance at those facilities.

Finally, the Company provided selected pages from a report prepared in 1993 that "supported the Company's decision to pursue modification of Martins Creek Units 3 and 4 to fire up to 50% with natural gas." Similar to the other studies, this report was not prepared for the purpose of optimizing the timing of retirements of the Company's generating capacity.

IV. LEVELIZATION OF SSES MSF DEPRECIATION

Q. Please describe the Company's request to "levelize" the Susquehanna modified sinking fund depreciation.

A. The Company's revenue requirement includes \$30.626 million to recover in the current test year the average of the post test year annualized increases under the SSES MSF depreciation schedule through 1998. The amounts included by the Company in its cost of service are \$30.388 million total Company and \$30.388 million PPUC jurisdiction. The Company also offered to voluntarily reduce its rates effective January 1, 1999 to reflect the completion of the MSF depreciation and the commencement of straight line depreciation.

To derive the increase in depreciation expense, the Company simply computed the average annual depreciation over the 39 months remaining between the end of the current test year (September 30, 1995) and the scheduled completion of the MSF depreciation (December 31, 1998). The Company's computation is detailed in its response to the Office of Trial Staff Interrogatories dated January 13, 1995, Q. RB-22D.

Q. **Does the "levelization" requested by the Company include any recognition of the carrying charge impact on ratepayers of accelerating the scheduled depreciation recovery?**

A. No. Contrary to the financial and economic connotations of the term "levelization," there is no carrying charge effect incorporated in the Company's computation. It is instead a simple "average" of the scheduled post test year increases.

Q. **Why should the Commission reject the Company's request to recover the additional costs related to the "levelization" of the SSES MSF depreciation?**

A. First, this request is clearly a lopsided attempt to reach beyond the end of the test year for a projected cost increase without taking into account other potentially offsetting reductions in costs or increases in revenues. Conceptually, the Company's request violates the overriding purpose of utilizing a defined test year, which is to ensure that revenues, expenses, investment, and cost of capital are treated in a consistent manner rather than manipulated to benefit either the utility or its ratepayers.

Second, the request actually will harm ratepayers. The acceleration of the depreciation recovery is not accompanied by an offsetting carrying charge benefit as would be required in order to actually levelize the effect on ratepayers. The

Company will obtain and retain the carrying charge benefit of prematurely collecting these amounts from ratepayers.

Q. **If the Commission rejects the Company's request, then won't the Company overrecover commencing January 1, 1999 when its SSES depreciation expense is reduced to straight line levels?**

A. Not necessarily. To ensure that overrecovery does not occur, the Commission has at least two options. First, it can direct in its order in this proceeding that the Company reduce rates on January 1, 1999 to reflect the reduction in SSES depreciation absent a showing that it has an offsetting revenue requirement deficiency. The Company would be directed to make a filing prior to that date in order to allow the Commission sufficient time to review the revenue requirement.

Second, the Commission could initiate on its own, or accept from another party, a complaint against PP&L in 1998 sufficiently in advance of the January 1, 1999 date to show cause why rates should not be reduced.

V. NUCLEAR DECOMMISSIONING

Q. Please describe the Company's request to increase the annual accrual for SSES decommissioning.

A. The Company's revenue requirement includes a request to increase the allowed annual decommissioning accrual for the Susquehanna units by more than four times the previous level. The Company has requested an increase in the cost of service from $7.126 million total Company to $30.042 million total Company and $23.570 million PPUC jurisdictional.

The most recent total projected cost of SSES decommissioning is estimated by TLG Services, Inc. on behalf of the Company at $804.259 million in 1993 dollars (total facility). That compares to the total projected cost last allowed by the Commission in Docket No. R-824651 of $266.804 in 1985 dollars (total facility).

Q. How did the Company compute the decommissioning accrual it has requested?

A. First, the Company commissioned TLG Services, Inc. to perform a new and site-specific study to determine the total projected decommissioning cost for the SSES facility. That total cost includes both nuclear (radioactive) and non-nuclear (nonradioactive) decommissioning costs. It also includes PP&L staff and other internal costs. Many assumptions were employed by TLG in the development of the total projected decommissioning cost. Among the assumptions was that in addition 5 or to its best estimate of the costs, contingency factors should be applied ranging from 10 ~~15~~% to 75% for various components. Second, the Company then annuitized the total projected decommissioning cost based upon an assumed after tax rate of return of 5.50%.

Q. What is the basis for the Company's use of a 5.50% after tax return?

A. The Company stated in response to discovery that the assumption was 1.50% over the projected 4.0% annual inflation rate. A more detailed computation was provided in response to other discovery including assumptions that no more than 30% of the trust fund would be invested in equities with an after tax rate of return of 8.5% and that 70% would be invested in debt securities including tax exempt bonds with an after tax rate of return of 4.6%. The tax rates assumed were 20% on debt and 15% on equities. The weighted return was projected at 5.80% after tax and 5.50% after tax and after fees and transaction costs. The Company's return projections also assumed that it would no longer be restricted to the so-called "Black Lung" investments which are historically lower earning and in which the trust fund is currently invested.

Q. What is the significance of the return on the trust fund investments?

A. It is significant for two reasons. First, the decommissioning accrual is directly dependent upon the return assumption. For example, doubling the projected after tax return to 11.0% from the Company's assumption of 5.50% reduces the annual accrual from $30.042 million total Company to $11.816 million total Company.

Second, the actual return earned directly affects the balance in the trust fund. If the fund earnings are higher than the assumption in the earlier years of the trust fund, then the accrual and funding can be reduced in the latter years. Alternatively, if the fund earnings are lower than the assumption in the earlier years, then the accrual and funding would need to be increased in the latter years.

Consequently, under the current regulatory construct, both the historical actual earned return and the projected return affect the annual accrual and, thus, the revenue requirement. The currently effective regulatory assumption is that the ratepayers are the guarantor of the Company's trust fund earnings performance.

Q. Should the Commission adopt the Company's proposed 5.50% after tax return assumption?

A. No. The Company's assumption of a 5.50% rate of return on ratepayers' funds is well below the return it claims is required on its own rate base investments. The Company should be paid to perform at a comparable level, not paid to perform at a startling assumed subpar level with the ratepayers responsible for the deficiency.

Contrast the 5.50% after tax return the Company has projected for the trust fund to the 10.23% after tax return on rate base it has requested in this proceeding. Contrast also the fact that the Company has assumed no risk for the return on the decommissioning fund (projected by TLG Services to reach at least $2,361.3 million by the date of decommissioning) with the fact that the Company is at risk as to whether it actually earns more or less than the authorized return on its rate base investment. For its entire rate base investment, the Company seeks authorization to collect a return before tax of 15.78% and earn after tax at 10.23%. For their multibillion dollar investment, the ratepayers are projected to be paid only a 6.88% before tax rate of return (5.50% grossed up to reflect a 20% tax rate) and earn after tax at only 5.50%. This differential is patently inequitable since the Company manages both its own rate base investments and the decommissioning trust fund investments.

In addition, the Company has no direct incentive to manage the trust fund aggressively on behalf of the ratepayers. This is evidenced by its suboptimal investment strategy, which is poorly structured to maximize returns for ratepayers.

For example, the Company has proposed to invest only 30% of the funds in equities. Yet equities have historically far outperformed other investments, according to data specifically cited by the Company in response to discovery. Further, the Company projects that it will continue to invest in tax-exempt securities. That simply does not make sense on an ongoing basis, since the expected returns on those types of securities are reduced to reflect the highest personal income tax rates, which are double the 20% tax rate on nuclear decommissioning fund earnings on non-tax-exempt securities.

Q. **What do you propose as a regulatory solution to the inequity of the returns and the lack of any direct incentive for the Company to aggressively manage the trust fund?**

A. The Commission should require the decommissioning accrual to be computed utilizing the allowed overall rate of return. That return should be updated in future base rate proceedings. However, this recommendation alone is insufficient if actual earnings are below the allowed rate of return.

I recommend that the Commission utilize the allowed overall rate of return as an earnings performance standard for the trust fund investments. To assure that ratepayers are not guarantors of poor and/or passive financial management performance by the Company, the Commission should impute earnings to the trust fund at the allowed rate of return. Thus, the Company will bear the risk and receive the benefit of its performance with ratepayers' funds just as it does with its investors' funds.

Q. Is it reasonable to expect the Company to earn its allowed after tax rate of return on the decommissioning trust fund investments?

A. Yes. There is substantial evidence presented by the Company's own cost of capital witness, Mr. Moul, that it should be able to earn comparably on investor and ratepayer supplied investment funds.

Mr. Moul testified that the after tax required return on common for a peer (barometer) group of companies was 13.0%, with a range of 11.97% to 13.94%. Thus, if its own witness is correct, then PP&L should be able to invest in the common equities of its peers and earn an expected rate of return of 13.0% on average.

Further, Mr. Moul testified that the after tax required return on common for the total "market of equities" is 15.85%, and that this is "a reasonable investor expectation." Thus, if its own witness is correct, then PP&L should be able to invest in a market based equity fund and earn that expected rate of return.

Taxes on these returns at the trust level would depend upon the level of dividends and capital gains distributions received. Assuming that 50% of the return is taxable annually and that the current federal tax rate of 20% on qualified nuclear decommissioning funds remains in effect, the net tax effect would be 10%. Thus, the expected after tax returns would range from 11.70% for a group of peer electric utilities to 14.27% for a market based equity fund, well above even the overall 10.23% after tax return sought by the Company.

Q. **What is the effect on the Company's cost of service and revenue requirement of your recommendation?**

A. At the Company's requested rate of return of 10.23%, the annual SSES nuclear decommissioning accrual would decrease from the $30.042 million total Company requested to $5.938 million total Company, a reduction of $24.104 million total Company and $18.911 million PPUC jurisdictional cost of service. This represents a reduction of $19.927 million in the requested revenue requirement. The computations are detailed on my Exhibit ____(LK-4), which is based upon the Company's Schedule D-11. The format of the Company's Schedule D-11 can be readily utilized to compute the effects of the overall rate of return actually authorized by the Commission in this proceeding.

VI. VOLUNTARY EARLY RETIREMENT PROGRAM

Q. Please describe the Company's request to recover the costs of its Voluntary Early Retirement Program.

A. The Company requested recovery of a projected $65.8 million in total costs amortized over a five-year period. Since the filing, the Company has updated, through responses to discovery, the projected cost to an actual cost of $75.859 million. The Company's updated cost of service for this item is $15.172 million total Company ($75.859 million/5 years). The projected savings are $38.661 million annually (total Company, for both capital and expense) and $27.915 million annually (total Company, for expense only).

Q. Did the Company reduce the total cost of the VERP for which it seeks recovery by the savings it projected to obtain prior to the end of the test year in this proceeding?

A. No. The Company did not reduce the total cost of the VERP deferred for regulatory recovery by the amount of the savings which it would have obtained by the end of the test year and by the date that rates from this proceeding are implemented.

Q. If the Commission allows recovery of the VERP costs, should the total cost first be reduced by the amount of savings the Company would otherwise retain?

A. Yes. The Company's request is clearly inequitable. It seeks to recover the gross cost of the VERP despite the fact that it was the also the direct beneficiary of nine months of VERP related savings from December 31, 1994 through September 30, 1995. If the Company is allowed recovery of the VERP costs, then recovery should be based on the net cost, not the gross cost.

Although the Company did reduce the test year O&M expense to reflect the ongoing savings, that effect is only prospective. However, the request for recovery of VERP costs is based upon the historic costs incurred prior to the date of the Commission's order in this proceeding. The historic costs actually incurred by the Company are not the gross costs but, rather, are the net costs computed as the gross costs recognized at December 31, 1994 less the savings it will have obtained prior to September 30, 1995.

Q. What effect does the utilization of the net cost of the VERP rather than the gross cost of the VERP have on the cost of service and the revenue requirement?

A. Utilizing the net cost of the VERP reduces the Company's cost of service, assuming the Company's proposed five year amortization, by $5.799 million total Company and

$5.019 million PPUC jurisdiction and reduces the revenue requirement by $5.289 million. The total annual savings (total Company capital and expense) are $38.661 million (provided in response to Office of Consumer Advocate, Set IV, Q. 75). The savings for the nine month period December 31, 1994 through September 30, 1995 are $28.996 million (annual savings of $38.661 million x 9/12 to prorate). The reduction in annual amortization expense would be the $28.996 million savings offset divided by the proposed five year amortization period.

The nine months of savings offset against the gross total VERP cost should be both capital and expense savings since the gross VERP cost requested by the Company is both capital and expense.

Q. Is the five year amortization period requested by the Company appropriate and reasonable?

A. No. First, the total cost of the VERP recognized at December 31, 1994 is not a cash cost. Only the lump sum payments are current cash expenditures. The Company projects that it will pay the residual of the VERP costs in the form of pension supplements and social security bridge payments for eleven years, from 1995 through 2005. Thus, under its proposal, the Company would obtain recovery of the pension supplements and social security bridge payments well in advance of the average payments for those items.

Second, as I discussed previously, the Company will have obtained and retained at least nine months of cash savings from the VERP. That $28.996 million of cash savings will more than offset the Company's lump sum payments totalling $19.000 million. This fact, coupled with the timing of the payments on the pension supplements and the social security bridge payments suggest a substantially longer amortization period than the five years proposed by the Company.

Q. What amortization period do you recommend?

A. I recommend that the Commission adopt a ten year straight line amortization period for the net VERP costs. The ten year period is equitable since it more closely parallels the actual payments under the VERP. In addition, it allows the Company the upfront and continuing carrying charge benefit of the excess of the nine months of savings compared to the lump sum payments.

Q. What is the effect on the Company's proposed cost of service and revenue requirement of extending the amortization period to ten years from five?

A. It would reduce the cost of service by $4.687 million total Company and $4.057 million PPUC and reduce the revenue requirement by $4.275 million, based upon the net cost of the VERP. These reductions are incremental to the previously discussed effects of utilizing the net, rather than the gross, cost of the VERP.

VII. SFAS NO. 106

Q. Please describe the Company's request to recover an amortization of prior period SFAS No. 106 amounts.

A. The Company has requested an annual cost of service of $1.797 million and a revenue requirement of $1.894 million to recover over 17.3 years the incremental SFAS No. 106 costs it incurred from January 1, 1993 through September 30, 1995. The balance at September 30, 1995 is projected by PP&L to be $31.095 million total Company and $31.095 million PPUC jurisdictional.

Q. Were these amounts authorized for deferral by the PPUC?

A. Yes. However, on May 26, 1994, the Commonwealth Court reversed the PUC order which granted the Company deferral authorization. As the result of the Court's order, the Company wrote off the amounts it had previously deferred and ceased deferring additional amounts.

Q. Should the Commission grant recovery of a cost disallowed by the Commonwealth Court?

A. No. I recommend that the Commission defer this issue to the Company's next base rate proceeding, presumably after the issue is resolved by the courts. Although the recovery of these costs is ultimately a legal question to be decided by the courts, any recovery of the costs through this proceeding is certainly premature and may be illegal.

If the costs are ultimately deemed by the courts to be legal and entitled to recovery, then the Company can seek recovery in its next base rate proceeding. Since there are no carrying costs associated with SFAS No. 106 expense accruals in excess of the cash pay as you go costs, the Company is not harmed by a delay in recovery if it is allowed by the courts.

If the costs are ultimately deemed by the courts to be illegal and not entitled to recovery, then no further action will be required by the Commission.

VIII. COST OF CAPITAL

Q. Have you quantified the effect of Mr. Baudino's recommendation of a 10.85% return on common equity on the Company's requested revenue requirement?

A. Yes. Adoption of Mr. Baudino's return on common equity recommendation would reduce the Company's requested revenue requirement by $84.687 million. That is the difference between the effective 12.87% return reflected in the Company's filing and Mr. Baudino's recommendation multiplied by the Company's requested common equity ratio, then multiplied by the Company's requested PPUC jurisdiction rate base and grossed-up for income taxes and other adders. Each 1.0% return in common equity translates to $41.924 million in revenue requirements, based upon the Company's filing.

Q. Have you quantified the effect of Mr. Baudino's capital structure recommendations on the Company's requested revenue requirement?

A. Yes. Adoption of Mr. Baudino's capital structure recommendation would reduce the Company's requested revenue requirement by an additional $5.017 million. The computations are detailed on Exhibit my ___ (LK-5).

Q. Does this complete your testimony?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

APRIL 1995

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Certified Management Accountants

Institute of Management Accountants

Seventeen years utility industry experience in the financial, rate, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

Kennedy and Associates: Vice President and Principal. Responsible for utility revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Minnesota, North Carolina, Ohio, Pennsylvania, Texas, and West Virginia Public Service Commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

- Rate phase-ins.
- Construction project cancellations and write-offs.
- Construction project delays.
- Capacity swaps.
- Financing alternatives.
- Competitive pricing for off-system sales.
- Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Consumers
Leheigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim 19th Judicial District Ct.	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebut	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebut	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of cancelled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

**Expert Testimony Appearances
of
Lane Kollen
As of March 1995**

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, guidelines for recovery.

Expert Testimony Appearances
of
Lane Kollen
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.

D. S. Hoch

Pennsylvania Power & Light Company
Response to Interrogatories of the
Office of Consumer Advocate, Set IV
Dated February 1, 1995
Docket No. R-00943271

Q. 87. Please identify each fossil fuel generating facility which PP&L has retired, the capacity of that facility, the date retired, the decommissioning cost and the amount of any salvage realized. Also state the disposition of the land subsequent to the decommissioning of the generating facility.

A. 87. Attachment 1 provides a list of fossil-fueled generating facilities which PP&L has retired noting the capacity and the date retired. Decommissioning costs and salvage and the disposition of the land have been noted where available.

Attachment 1

Station	Retirement Date	Capacity (MW)	Decommissioning Amount	Salvage
Millersburg	1951	4.250	10,630.01	20,512.63
Locust Spring	1951	6.000	20,863.53	60,617.40
Swengel	1951	0.200	7,295.48	4,586.04
Carlisle	1951	2.000	11,608.42	10,147.40
Walnut	1951	1.750	1,377.75	981.67
Lock Haven	1952	4.500		93.15
Bennett	1952	2.000	1,461.16	8,414.98
South Milton	1953	8.000	3,008.40	44,685.63
Good Spring	1953	8.000	201.48	19,625.00
Allentown	1953	38.812	28,383.37	102,434.95
Kulpmont	1953	12.000	8,821.27	38,059.79
Lykens	1953	15.400	2,963.96	58,042.92
Williamsport	1953	20.000	138.14	22,570.54
Suburban #3 & #6	1956	14.000	66,550.12	84,919.47
Illuminating	1956	5.700	13,125.60	23,410.93
Suburban LP	1957	48.000		
Cedar	1962	27.000	7,612.16	38,891.43
Harwood	1962	41.500	937.32	71,048.65
Pine Grove	1965	55.000	5,519.93	183,680.00
Suburban #7	1967	25.000	42,104.10	12,741.30
Hauto	1969	70.000	12,647.86	34,055.56
Stanton	1972	50.000	618.71	110,020.00
Holtwood LP	1972	30.000		
Suburban	1988	29.250	707,375.89	68,259.99
			953,200	1,017,700

Station	Site Use
Millersburg	Storage
Locust Spring	Sold
Swengel	Sold
Carlisle	Sold
Walnut	Sold
Lock Haven	Sold
Bennett	Sold
South Milton	Sold
Good Spring	Sold
Allentown	Sold
Kulpmont	Sold
Lykens	Sold
Williamsport	Sold
Suburban #3 & #6	SES- Demolished
Illuminating	Unknown
Suburban LP	Unknown
Cedar	Sold
Harwood	SES- Demolished
Pine Grove	Sold
Suburban #7	SES- Demolished
Hauto	SES- Demolished
Stanton	SES- Demolished
Holtwood LP	Units Removed
Suburban	SES- Demolished

D. S. Hoch
J. M. Kleha

Pennsylvania Power & Light Company
Response to Interrogatories of
PP&L Industrial Customer Alliance, Set IV
Dated March 13, 1995
Docket No. R-00943271

Q. 1. a. For each generating plant/unit and each category of general plant for which the Company is seeking longer or shorter depreciation lives, please provide the depreciation expense included in the test year budget and the proforma depreciation expense. Please provide all supporting assumptions, workpapers, and computations.

b. For each generating plant/unit and each category of general plant reflected in your response to part (a) of this question, please provide the total Company and PA. PUC jurisdictional revenue requirement. Provide all supporting assumptions, workpapers, and computations.

A. 1. a. Attachment 1 provides the total Company test year budget and proforma depreciation expense for each generating plant and each general plant account for which the Company is seeking longer or shorter depreciation lives. Attachment 1 also provides the PUC jurisdictional portion of the Company's test year budget and claimed proforma depreciation expense. See the response to Question OTS-RB-13D Dated January 13, 1995 and Exhibits Future 1 and JMK 2 for details.

b.

		Shorter Lives Fossil Production Only
PUC jurisdictional portion of claimed proforma depreciation expense - Attachment 1	$42,126	$29,946
PUC jurisdictional portion of test year budget depreciation expense - Attachment 1	28,655	13,259
Increase in expense	13,471	16,687
Change in PUC jurisdictional deferred income tax expense due to claimed increase in depreciation expense - Attachment 2	(4,962)	(6,053)
Net change in operating income	$8,509	$10,634
Applicable revenue requirements	$15,381	$19,222
	1.8076	

Attachment 1

Pennsylvania Power & Light Company

	Total Company FTY Budget Depreciation Expense ($000)	Jurisdictional Portion of FTY Budget Depreciation Expense ($000)	Total Company Proforma Depreciation Expense ($000)	PUC Jurisdictional Portion of Pro Forma Depreciation Expense ($000)
Steam Production				
Sunbury	$8,492	$6,920 ✓	$18,737	$15,269 ✓
Martins Creek 1 & 2	6,048	4,929 ✓	15,046	12,261 ✓
Conemaugh	5,920	5,018	4,233	3,588
Keystone	4,144	3,512	2,631	2,230
Holtwood	1,705	1,389 ✓	2,926	2,384 ✓
Hydro Production				
Wallenpaupak	274	232	255	216
Holtwood	1,191	1,010	1,629	1,381
Other Production				
Sunbury Diesel	11	9 ✓	11	9 ✓
Sunbury CT	8	7 ✓	18	16 ✓
Martins Creek Diesel	3	2	3	2
Martins Creek CT	6	5 ✓	8	7 ✓
Conemaugh Diesel	3	3	2	2
Keystone Diesel	3	3	2	2
Total Fossil Production Shorter Lives (Facilities Marked with ✓)			13,259	29,946
General Plant				
390.2	4,032	3,486	2,628	2,272
390.4	511	441	154	133
391.2	455	393	535	462
391.4	101	87	147	127
392.4	1	1	2	2
393.0	65	56	72	62
394.0	55	47	115	99
394.4	339	293	544	470
394.6	92	80	166	144
394.8	324	280	384	332
395.0	108	93	302	261
397.0	321	278	321	278
398.0	94	81	135	117
Total	$34,306	$28,655	$51,006	$42,126

Pennsylvania Power & Light Company
Deferred Income Tax Calculation
Due to Excess of Tax Depreciation Over
Depreciation Using Tax Basis and Book Rates
Rate Case - Future

		ACRS/MACRS Depreciation	Deprec Using Tax Basis & Book Rates	Excess Depreciation	Rate	Adjusted Deferred Taxes	Filed Amount Deferred Taxes	Adjustment-Deferred Taxes
NUCPR-SSES #1		12,199,868	51,346,415	(39,146,547)	ARAM/.35	(16,601,676)	(16,601,676)	0
NUCPR-SSES #2		7,962,529	47,729,221	(39,766,692)	ARAM/.35	(15,754,928)	(15,754,928)	0
NUCPR-COMMON		13,833,443	33,128,920	(19,295,477)	ARAM/.35	(8,284,123)	(8,284,123)	0
Total-NUCPR	(1)	33,995,840	132,204,556	(98,208,716)		(40,640,727)	(40,640,727)	0
OTHER:								
CLERT		281	15,012	(14,731)	ARAM/.35	(6,741)	(6,741)	0
CLERD		1,332,428	382,056	950,372	ARAM/.35	325,124	325,124	0
F & F		679,014	290,948	388,066	ARAM/.35	124,768	(268,689)	(393,457)
CMPTR		1,912,790	5,709,361	(3,796,571)	ARAM/.35	(1,283,206)	(1,283,206)	0
EQUIP		47,996	61,739	(13,743)	ARAM/.35	(7,099)	(66,476)	(59,377)
TRAIL		723	283	440	ARAM/.35	152	59	(93)
STMPR		61,724,838	39,809,632	21,915,206	ARAM/.35	7,624,283	3,332,814	(4,291,469)
HYDPR		4,263,960	1,043,430	3,220,530	ARAM/.35	1,127,188	1,010,410	(116,778)
T & D		95,652,786	44,475,133	51,177,653	ARAM/.35	17,872,001	16,996,927	(875,074)
GBLDG		3,891,633	2,752,319	1,139,314	0.3500	398,762	766,965	368,203
VEHICLES & EQUIPMENT		15,730,903	7,650,634	8,080,269	ARAM/.35	2,828,380	2,828,380	0
Total-OTHER	(2)	185,237,352	102,190,547	83,046,805		29,003,612	23,635,567	(5,368,045)
LEASEHOLDS	(2)	346,981	1,264,151	(917,170)	ARAM/.35	(321,198)	(321,198)	0
TOTAL EXCLUDING NUCLEAR FUEL		219,580,173	235,659,254	(16,079,081)		(11,958,313)	(17,326,358)	(5,368,045)
NUCLEAR FUEL	(1)	34,105,399	47,234,000	(13,128,601)	0.3438	(4,513,613)	(4,513,613)	0
GRAND TOTAL		253,685,572	282,893,254	(29,207,682)		(16,471,926)	(21,839,971)	(5,368,045)
SUMMARY								
SUSQUEHANNA (1)		68,101,239	179,438,556	(111,337,317)		(45,154,340)	(45,154,340)	0
NON SUSQUEHANNA (2)		185,584,333	103,454,698	82,129,635		28,682,414	23,314,369	(5,368,045)
		253,685,572	282,893,254	(29,207,682)		(16,471,926)	(21,839,971)	(5,368,045)
PUC JURISDICTIONAL NON SUSQUEHANNA						26,512,000	21,550,000	(4,962,000)

	PPUC Jur	Tot Co
Increase in Fossil Depr	16,687	20,476
Ratio of Stmprd Tax Depr to Book Depr (39,810/43,573)		91.36%
		18,708
Tax Rate		35%
Incremental Def Tax Effect		6,548
PPUC Jur (4,962/5,368)		92.44%
PPUC Jur Increase Def Tax		6,053

Exhibit ___ (LK-4)
D-11
R. J. Bernini

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Annual Accrual for Decommissioning Expense
Year Ended September 30, 1995
(Thousands of Dollars)

This adjustment provides for an annual accrual of decommissioning expense associated with the Susquehanna Steam Electric Station (SSES), based upon the total estimated cost of immediate dismantlement of the facility.

Line No.	Description		Amount Unit 1	Unit 2	Total	
1	Cost of decommissioning in 1993 dollars		$350,524	$453,735	$804,259	
2	PP&L share (90%)		$ 315,471	$ 408,361	$ 723,832	
3	Rate of inflation		4%	4%		
	Years to Retirement					
4	Unit 1 (1994-2022)		29			
5	Unit 2 (1994-2024)			31		
	Cost of Decommissioning					
6	Unit 1 (line 2 x 3.118651 (a))		$983,844			
7	Unit 2 (line 2 x 3.373133 (b))			$1,377,456	$2,361,300	
8	Value of trust @ 9/30/95		$56,548	$41,717	$98,265	
9	Earnings on trust (c)		~~5.50%~~ 10.23%	~~5.50%~~ 10.23%		
	Value of Trust					
10	@ 2022 (line 8 x 4.244401 (d))	$784,354	~~$240,012~~			
11	@ 2024 (line 8 x 4.724124 (e))			$703,084 ~~$197,076~~	~~$437,088~~	$1,487,438
	Net Cost of Decommissioning					
12	Unit 1 (line 6 - line 10)	$199,490	~~$743,832~~			
13	Unit 2 (line 7 - line 11)			$674,372 ~~$1,180,380~~	~~$1,924,212~~	$873,862
	Annuity Amount					
14	Unit 1 (line 12 x .016952 (f))	$1,586	~~$12,609~~			
15	Unit 2 (line 13 x .014769 (g))			$4,352 ~~$17,433~~	~~$30,042~~	$5,938
16	Less: Amount per budget		3,818	3,308	7,126	
17	Increase in expense		~~$8,791~~ $(2,232)	~~$14,125~~ $1,044	~~$22,916~~ $(1,188)	

a) Future value of $1 with compound interest @ 4% for 29 years.
b) Future value of $1 with compound interest @ 4% for 31 years.
c) Reflects an after tax rate of return of 1.5% above the assumed rate of inflation.
d) Future value of $1 with compound interest @ 5.5% for 27 years.
e) Future value of $1 with compound interest @ 5.5% for 29 years.
f) Periodic deposit that will grow to $1 in 27 years with interest compounded @ 5.5%.
g) Periodic deposit that will grow to $1 in 29 years with interest compounded @ 5.5%.

$30,042
(5,938)
$24,104
PPUC 78.456%
$18,911

Exhibit ____(LK-5)

REVENUE REQUIREMENT EFFECT OF BAUDINO CAPITAL STRUCTURE RECOMMENDATION

	Common	Preferred	LTD	Total
Company's Capital Structure	45.88%	7.59%	46.53%	100.00%
Company's Cost of Capital[1]	10.85%	7.31%	7.97%	
Company's Weighted Cost of Capital	4.98%	0.55%	3.71%	
Gross-Up Factors	1.8213	1.8213	1.0537	
Company's Grossed-Up Cost of Capital	9.07%	1.01%	3.91%	13.99%
Company's 9/30/94 Capital Structure	44.96%	7.91%	47.13%	100.00%
Company's Cost of Capital[1]	10.85%	7.31%	7.97%	
Recommended Weighted Cost of Capital	4.88%	0.58%	3.76%	
Gross-Up Factors	1.8213	1.8213	1.0537	
Baudino's Grossed-Up Cost of Capital	8.88%	1.05%	3.96%	13.89%
Reduction to Grossed-Up Cost of Capital				0.10%
Company's Requested Rate Base (PPUC Jur.)				5,017,178
Reduction to Company's Revenue Requirement				$5,017

(1) Cost of common based on Baudino recommendation.