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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

Direct Testimony and Exhibits
of
Dale G. Bridenbaugh

On Behalf of
Pennsylvania
Office of Consumer Advocate

April 1995

PREPARED DIRECT TESTIMONY

OF DALE G. BRIDENBAUGH

On Behalf of

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

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GLOSSARY

BWR	Boiling Water Reactor
DECON	Decommissioning option: immediate dismantlement after reactor ceases operations
DOE	U.S. Department of Energy
ENTOMB	Decommissioning option: entombment (sealing radioactive materials with concrete and steel)
GAO	U.S. General Accounting Office
LLRW	Low-Level Radioactive Waste
NRC	U.S. Nuclear Regulatory Commission
NUREG	Regulatory Guidance Document from the NRC
O&M	Operations and Maintenance
PNL	Battelle Pacific Northwest Laboratory
PP&L	Pennsylvania Power and Light Company
PWR	Pressurized Water Reactor
SAFSTOR	Decommissioning option: safe storage or mothballing, restricted entry by manned security force
TLG	TLG Engineering

PREPARED DIRECT TESTIMONY

OF DALE G. BRIDENBAUGH

I. INTRODUCTION

Q: What is your name and position?

A: My name is Dale G. Bridenbaugh. I am a co-founder and president of MHB Technical Associates, technical consultants on energy and the environment, with offices at 1723 Hamilton Avenue, Suite K, San Jose, California. I also serve as a principal consultant for the firm.

Q: Please describe your qualifications and experience.

A: As president and co-founder of MHB Technical Associates, I have provided technical advice to various governmental bodies and individual groups on subjects related to the design, operation, and economic aspects of commercial nuclear power plants. I have served in various consulting capacities to the United States General Accounting Office, and the Nuclear Regulatory Commission (NRC); to state consumer agencies, offices of attorneys general, rate setting commissions and other state offices in California, Connecticut, Florida, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Jersey, New York, Ohio, Pennsylvania, Texas, and Vermont; to Suffolk County, New York; to the Cities of Riverside, California and El Paso, Texas; and to the governments of Sweden and Norway, all in the evaluation of nuclear plants or programs.

Prior to the formation of MHB Technical Associates, I worked from June 1953 until February 1976 as an engineer and manager with the General Electric Company (General Electric or GE) on many aspects of power generation equipment design, manufacture, and operation. During my last ten years at

General Electric, I held management positions in the Nuclear Energy Division where I managed the monitoring of nuclear power plant operations, the implementation of solutions to nuclear plant operational problems, and the development of a master performance improvement plan for power reactors. Prior to my management assignment in the Nuclear Energy Division, I spent several years as a field engineer at the first large scale commercial nuclear power plant built by General Electric for Commonwealth Edison Company at Dresden, near Chicago. There I supervised the construction, start-up, modifications, and repair of various portions of the plant. During this time, I was General Electric's site manager for the first major refueling and maintenance outage at the Dresden plant.

I received a B.S. in Mechanical Engineering from the South Dakota School of Mines and Technology in 1953, and I am a registered professional nuclear engineer in the state of California and a member of the American Nuclear Society. Further details of my experience and training are summarized in my Statement of Professional Qualifications which is appended to this testimony as **Exhibit DGB-1**.

Q: Have you previously testified in cases before the Pennsylvania Public Utility Commission (PUC)?

A: Yes, I have done so several times. Following is a list of cases before the PUC in which I have participated:

Utility/Plant	Subject	Year	Docket
DLC/Beaver Valley	Outage	1982	
PP&L/Susquehanna	Cost of Construction	1983	R-822169
DLC/Beaver Valley	Seismic Analysis	1987	I-79070318
DLC/Perry	Evaluation of Power Ascension Program	1987	R-870651 & R-870732

Utility/Plant	Subject	Year	Docket
PECO/Salem	Seventh Refueling Outage	1988	I-880082, M-880189, M-880189C001 M-880189C002
PECO/Limerick	Unit 2 Construction	1989	R-891364
MET-ED/TMI-1 & -2 & Saxton	Decommissioning, O&M, Cap Adds	1992	R-922314

Q: Was this testimony prepared by you or under your direction?

A: Yes it was.

II. TESTIMONY SCOPE AND SUMMARY OF CONCLUSIONS

Q: What is the purpose of your testimony?

A: The purpose of this testimony is to present for the consideration of the Pennsylvania Public Utility Commission (PUC) the results of a review conducted on behalf of the Office of Consumer Advocate, concerning nuclear cost issues related to Pennsylvania Power & Light Company's (PP&L) Susquehanna Steam Electric Station (SSES). The issues under review included the SSES Decommissioning Cost Estimate validity, and:

(a) To what extent, if any, should the costs for decommissioning the non-radiological portion of the plant be included in rates at this time;

(b) The reasonableness of the contingency included in PP&L's estimate; and

(c) The reasonableness of PP&L's estimate of the cost for disposal of low-level radioactive waste (LLRW)~~, and~~

Q: How is your testimony organized?

A: My testimony is organized into the following sections:

Section II: Testimony scope and a summary of conclusions;

Section III: Decommissioning issues, including a description of PP&L's decommissioning request, a description of nuclear decommissioning background, non-radiological decommissioning expenses, and the contingency factor;

Section IV: Conclusions and recommendations.

Q: Would you please briefly summarize the recommendations that you have concerning the nuclear decommissioning-related issues?

A: I recommend reducing the 100% amount estimated for SSES decommissioning ($804.3 million) to $573.0 million. The basis for this reduction is removal of the non-radiological portion of the plant from the estimate, and removing the remaining contingency factor from the cost estimate for the radiological portion of the plant.

Q: How do these recommended changes affect revenue requirements as requested by the Company?

A: The changes that I have recommended, as indicated in the paragraph above, have been given to OCA's financial witness for inclusion in his testimony.

III. DECOMMISSIONING ISSUES

A. PP&L DECOMMISSIONING REQUEST

Q: What is PP&L requesting be changed in the provisions for decommissioning allowances?

A: PP&L is basing its decommissioning request on a site specific decommissioning cost estimate prepared by TLG Engineering. The full costs (rounded) to decommission the plant, if it were to be in 1993, are listed below:

	Radiological	Non-Radiological	Total
Unit 1	$304.9 million	$45.7 million	$350.5 million
Unit 2	$372.0 million	$81.7 million	$453.7 million
Total	$676.9 million	$127.4 million	$804.3 million

These "overnight" [1] costs are then escalated to the future time when decommissioning is planned to occur, and this amount is then used to calculate annual payments. Escalation is somewhat offset by returns on amounts set aside in the decommissioning trust fund.

Q: Do you have any adjustments to make?

A: Yes. I recommend that the overnight amounts (rounded) be adjusted for ratemaking to the following amounts:

	Radiological	Non-Radiological	Total
Unit 1	$257.5 million	$0	$257.5 million
Unit 2	$315.5 million	$0	$315.5 million
Total	$573.0 million	$0	$573.0 million

1/ "Overnight" costs are used to represent the total cost and are stated as if the decommissioning were to occur instantaneously, with no inflation.

Q: Please explain these recommended adjustments.

A: These adjustments are explained in detail below.

B. BACKGROUND

Q: Please define decommissioning.

A: Decommissioning occurs once a nuclear facility has reached the end of its useful life. It is the process by which a nuclear facility is safely removed from service and radioactive materials are disposed of without incurring unreasonable risk to public health and safety. Current regulations require that the level of residual radioactivity remaining on the property after decommissioning ultimately must be low enough to allow unrestricted use of the property and termination of the license. However, new draft proposed rules on site release criteria would allow termination of a license with some restricted uses.

Decommissioning is required by the Nuclear Regulatory Commission (NRC) under present regulations. General guidance is contained in NRC Regulatory Guide 1.86, Termination of Operating Licenses for Nuclear Reactors. The NRC published rules on decommissioning on June 27, 1988, which established a methodology to calculate the minimum amount needed to be set aside for decommissioning, establishes a cost escalation formula to periodically adjust the estimate, contains information on acceptable decommissioning methods, and contains guidance on how to terminate a license. Because the NRC is only concerned with health and safety issues regarding the use of radioactive materials, it does not have regulations or guidance regarding decommissioning of non-radiological portions of the plant.

In 1990 NRC published Reg. Guide 1.159, which outlines the requirements for assuring the availability of funds for decommissioning. A minimum level of financial responsibility, in 1986 dollars, for a Boiling Water Reactor (BWR) is $135 million and for a Pressurized Water Reactor (PWR) is $105 million. These amounts were based on a series of site-specific studies conducted by Battelle Pacific Northwest Laboratory (PNL). These levels are adjusted to account for plant size and are updated periodically to account for escalation of labor, energy costs and waste burial charges. Waste burial charges are updated in an NRC Report, NUREG-1307. The regulations and the guidance documents also provide acceptable funding methods for assuring that money is available to cover future costs.

The PNL estimates have recently been updated, but they are still in draft stage. The latest BWR estimate is $158.2 million; the latest PWR estimate is $124.6 million, both in 1993 dollars. [2] The PNL BWR estimate is based on the design detail of the WNP-2 plant, a single-unit 1155 MWe GE Boiling Water Reactor, a plant with a similar configuration and rating to each of the two units at SSES. It is noteworthy that these latest PNL cost estimates, when compared to the earlier PNL estimates, have increased at a rate lower than the inflation rate used by PP&L (i.e. 4%). [3]

There are three decommissioning options that are commonly considered acceptable by the NRC. They are immediate dismantlement of the reactor, mothballing for later dismantlement while residual radioactive material decays, and entombment in steel and concrete. These options are designated by NRC as DECON, SAFSTOR, and ENTOMB, respectively. Additionally, the NRC leaves an option of conversion of the plant so that it will continue to generate electricity. Decommissioning costs may vary depending upon which of those options is

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[2] NUREG/CR-5884, Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Station, October 1993 (Draft for Comment), and NUREG/CR-6174, Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Station, September 1994 (Draft for Comment), p. XIX.

[3] The 1986 estimate of $105 million for the reference PWR would be $138 million in 1993 dollars at a 4% inflation rate; the 1986 estimate of $135 million for the reference BWR would be $178 million in 1993 dollars at a 4% inflation rate.

employed. The three major technical options are described below:

1) **DECON** (immediate dismantlement) involves the removal of all radioactive materials shortly after the cessation of operations. It entails removing from the site all fuel assemblies and spent fuel, fission and corrosion products, and all other radioactive materials with radioactivity above certain levels, after which the licensee has unrestricted use of the site.

2) **ENTOMB** (entombment) defers access for many years by sealing radioactive materials with concrete and steel. All fuel is removed from the site before entombment, and the reactor internals may also be removed before the facility is sealed. Residual radioactive materials are allowed to decay over many years in the entombed structure.

3) **SAFSTOR** (mothballing) also defers access to a later date while allowing residual materials to decay to a reduced level of radioactivity. However, while the entombment option actually seals the plant with concrete in order to safeguard the plant, SAFSTOR relies upon a manned security force during the dormancy period. Once fuel, radioactive liquids and wastes are removed from the site, activities consist of radiation surveys, environmental surveillance, and implementing security, surveillance and maintenance plans for the delay period. Delayed dismantlement activities are required to be completed within 60 years.

Q: Has there been sufficient decommissioning experience to judge the validity of the company's estimates?

A: No. Although there have been several decommissioning projects that have taken place in the past few years, in which valuable information has been gained about decommissioning techniques, the projects have either not been fully completed, or they have not been of the same scale as the Susquehanna plant. Most of the experience comes from plants that have been closed prematurely (Shoreham, Trojan, Fort Saint Vrain, Yankee Rowe, and Rancho Seco) or smaller research reactors.

Q: What are the major uncertainties in estimating decommissioning costs?

A: Major uncertainties inherent in decommissioning cost estimates include: how factors such as working in areas with restricted space and low-levels of radioactivity contribute to additional costs; to what extent technology developed for decommissioning during the early experiences with large-scale commercial units will decrease costs; to what extent utilities will be able to decrease waste volumes; how unavailability of space for low-level and high-level waste will affect costs; and to what degree federal and state policy on waste disposal and allowable levels of radiation will affect costs.

Currently, only one small commercial-scale reactor (Shippingport, 65 MWe) and several small research reactors have been fully decommissioned. Notwithstanding this experience, and the experience gained from partial decommissioning activities at Shoreham, Trojan, Fort Saint Vrain, Yankee Rowe, and Rancho Seco, I expect that applying decommissioning technology on a large scale will face many potential difficulties. Technology and techniques have been developed for isolating systems, waste handling, controlling explosives for pipe cutting and concrete demolition, remote segmentation of highly radioactive components and surveillance practices. I expect that as more experience is gained, these techniques will be adapted and scaled, and new techniques will be developed. This would likely place downward pressure on certain of the costs of decommissioning.

In this context, utilities and regulatory agencies are facing the difficult task *of estimating the costs of future decommissioning so that the ratepayers benefiting* from a plant pay their fair share of the future cost for those benefits.

Q: Why is it important that state regulatory commissions approve the most accurate estimates of decommissioning costs?

A: There are several major policy principles involved.

The first principle is to provide protection of public health and safety. It is particularly important that funds be available for decommissioning at the end of the facilities' useful life, as lack of funds may limit the licensee's ability to select and complete the most appropriate alternative. This principle forms the basis for the NRC's regulations whereby utilities are required to set aside sufficient funds for decommissioning. The fund must be fully funded when the plant ceases operations.

The second principle is that the rate effects of decommissioning should be borne equitably by all of the beneficiaries of power resource (i.e. the costs of decommissioning are paid by contemporaneous users of facility). An important corollary to this principle is that the risks of over collection or under collection should be borne equitably among the beneficiaries of the power resource.

A third principle is to promote economic efficiency. When the plant is to be decommissioned, the lowest-cost method that provides adequate protection to public health and safety should be chosen. Should utilities accumulate more funds than necessary for the least-cost method, there is little incentive to choose that method because the utility would not benefit financially from the savings. This principle is often overlooked.

Q: How have most state ratemaking commissions dealt with these issues?

A: The response of state ratemaking bodies has varied considerably, as have the estimates submitted to them by utilities. The system that has evolved, however, is that most rate commissions expect cost estimates to be as accurate as possible, and estimates are reviewed and updated periodically. This is either done each base rate case, or on a schedule, such as every three years. PP&L has stated that it plans to internally update its cost estimate every 2 years. [4]/

Q: How are costs for decommissioning usually estimated?

A: There are two prevalent estimating methods that are used. One method is based on a series of reports by Battelle Pacific Northwest Laboratory (PNL), which were commissioned by the NRC. [5]/ This is often referred to as a "generic" method. Taking the results of these reports, the NRC has established a basic level of financial responsibility for holders of a nuclear license, and also has set down regulations on assuring that funds will be available when the time comes to decommission the plant. These amounts were based on two site-specific studies conducted by PNL. As stated above, the basic level of financial responsibility, in 1986 dollars, for a Boiling Water Reactor (BWR) is $135 million and for a Pressurized Water Reactor (PWR) is $105 million. These levels are adjusted to account for plant size, and are updated periodically to account for escalation of

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[4]/ See Response to OCA-VIII-1. Also see, PP&L Response to OCA-II- 2.

[5]/ NUREG/CR-0130, Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station, June 1978 and addendum, and NUREG/CR-0672, Technology, Safety and Costs of Decommissioning a Reference Boiling Water Reactor Power Station, June 1980 and addendum

labor, energy costs and waste burial charges. This method served as the basis for PP&L's previous decommissioning cost estimate in 1985.

The second method is based on a report and model by Atomic Industrial Forum (AIF). [6]/ This is often referred to as a "site-specific" method, although it has many of the same generic qualities as the PNL method. It takes site-specific quantities, and runs them through a computer code, to develop an estimate. Thousands of calculations are made. One of the developers of this method is Mr. LaGuardia. The important methodological difference between the two methods is that the AIF method applies unit-cost factors to site-specific inventories and considers some site-specific attributes to develop its estimate.

As stated previously, PNL is in the process of updating its decommissioning study for the NRC. The results of this latest study have been issued in draft form. The study update uses unit-cost factors to develop generic cost estimates, similar to the AIF method. The results of the update are very similar to the generic estimate used previously, and much lower than TLG estimates for similar plants. However, it should be noted that PNL has made a significant change in assumptions which are not included in the new estimates; that is, the PNL draft recognizes that spent nuclear fuel will need to be cooled in on-site wet storage pools for five-years before DOE will accept it. In the PNL update, these costs are treated as operating costs and are not assigned to decommissioning. PNL did perform a sensitivity study and found that if the "five-year" costs were treated as decommissioning costs (as the TLG estimate assumes), that the cost could

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[6]/ AIF/NESP-036, Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates, May 1986

increase by approximately $40 million. [7] I believe that the five-year spent fuel storage costs are legitimate costs, although these costs could be considered to be fuel-related rather than strictly decommissioning costs. For a dual unit plant, there will be an opportunity to avoid some of these costs on the first unit, as security and staff will still be charged to operations, and the two units share the same storage pool. Therefore, for a dual unit decommissioning based on the PNL estimate, the extra cost would be somewhat less than adding $80 million.

Q: Have other Commissions or utilities adopted the PNL methodology?

A: Yes, it has been accepted by many jurisdictions with nuclear facilities. In early 1990, MHB conducted a survey of 37 utility rate commissions. Eight identified that they had approved decommissioning accruals which used the PNL study as the basis for the estimate(s); eight others identified estimates using a "generic" methodology which used the PNL estimate as a starting point. Additionally, in a recent rate case in Illinois, Commonwealth Edison used the PNL methodology as a starting point for its estimated 13 nuclear units. These were adjusted to account for regional factors and in some cases, site specific factors.

Q: Do you recommend using the PNL methodology?

A: Generally not. I believe that a site-specific estimate which takes into account factors such as material quantities, plant design, and differing levels of radioactivity is more appropriate. The NRC adopted the PNL generic method to establish a floor: "minimum amounts" which are required to demonstrate reasonable assurance that the utility has the financial ability to complete decommissioning. I believe, however, that the PNL studies are useful and should

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7/ NUREG/CR-6174, Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Station, September 1994 (Draft for Comment), p. xx.

be used to check the reasonableness of site-specific estimates. I have done such a comparison in this particular case.

Q: What did your comparison of the PNL estimates to the decommissioning estimates for Susquehanna indicate?

A: It indicated two things. First, that the results of the TLG estimate are similar to that of PNL, if certain assumptions are used. Second, and most importantly, it brings into focus the major variable that affects the decommissioning cost estimate: that is, the assumed cost of low-level radioactive waste (LLRW) burial.

The TLG estimate for the radiological portion of the plant is $676.9 million. The PNL estimate for the radiological portion of one unit is $158.2 million. Thus, the radiological portion for a dual unit plant, (treating the plant as two single-unit plants, which is a conservative assumption), would be $316.4 million. However, this number is not yet comparable to the TLG estimate because of two other factors. As stated above, the five-year delay in cooling of spent-fuel, not considered as a decommissioning cost by PNL, would add approximately $40-80 million to that total. In addition, LLRW waste costs for the PNL reference plant are based on rates of an assumed active regional disposal site in Washington state. The PNL study posits that if Barnwell South Carolina LLRW disposal rates were used (as TLG has used in its study for Susquehanna), it would add another $147.6 million per unit, or $295.2 million for the two-unit facility. With these added costs, radiological decommissioning for both units would come to $691.6 million, slightly higher than the TLG estimate of $676.9 million. However, if this adjusted PNL estimate were strictly applied to a two-unit plant, I believe it would be reduced because it would take advantage of economy of scale savings, and the overlapping of management and support staffs as well as the use of nearly identical work plans for the duplicate units. The PNL amount also includes a 25% contingency factor and in calculating the effect of Barnwell disposal costs did not assume volume reductions as disposal cost rates increased. Accordingly, the two estimates (PNL and TLG) are quite comparable, <u>if one assumes the Barnwell (with surcharge) disposal costs</u>.

Q: What is the significance of your finding that the two studies produce similar costs if Barnwell disposal costs are assumed?

A: This finding emphasizes that the two estimates are similar only if they assume the high Barnwell LLRW surcharges. The total cost of decommissioning is artificially inflated, and argues for the use of great care in accepting such an estimate without acknowledging that added conservatism. The SSES LLRWs are not going to be disposed of at the Barnwell facility, with its associated and inapplicable surcharge. I conclude that the TLG estimate is inflated because of this assumption.

C. <u>NON-RADIOLOGICAL DECOMMISSIONING</u>

Q: What amount is PP&L requesting for non-radiological decommissioning?

A: PP&L requests that it collect annual payments to cover removal of buildings at Susquehanna that have not been subjected to ionizing radiation, such as cooling towers, gatehouses, and administration buildings. These annual payments are to be based on an overnight dismantlement cost estimate of $127.4 million. Currently, the annual collections for decommissioning do not include non-radiological decommissioning.

Q: What is your recommendation regarding non-radiological decommissioning costs.

A: I recommend excluding these costs from rates at this time.

Q: At page 11 of Exhibit TSL-1, Mr. La Guardia cites some language from the Building Official and Code Administrators National Building Code that he interprets as requiring the removal of all of the non-radiological structures from the site at the time of decommissioning. Are the requirements of that Code directly applicable to the Susquehanna site?

A: I do not believe so. The Code only requires that unsafe structures dangerous to the public or being subjected to improper use be removed or made safe and secure. The Susquehanna site is, and no doubt will be, fenced and guarded for the foreseeable future. It is a valuable resource that PP&L will likely continue to use at least as a transmission interconnection, and will probably use in some form as a generating station location. Public access is thereby precluded.

Q: Do the regulations governing nuclear decommissioning require that the decommissioning cost estimates include the task of decommissioning the non-radioactive components of the plant?

A: No. The NRC, as reflected in the PNL studies, limits its concerns to health and safety issues regarding the use of radioactive materials, and therefore it does not have regulations or guidance regarding decommissioning of non-radiological portions of the plant.

Q: Are there other reasons why these costs should be excluded.

A: Yes. I recommend excluding all non-radiological decommissioning expenses because PP&L has not yet developed a long range plan that considers the future use of the SSES site. Such a plan is needed before including costs which ratepayers may not be required to pay. The plan should evaluate the benefits and costs of demolishing buildings not required to be destroyed by regulation, and should seriously evaluate potential re-use of the site. It is the burden of the company to demonstrate that existing buildings will not be of use before complete dismantlement can be justified.

Q: Please describe the basis for this assertion.

A: Except for the remaining parts of the buildings which have endured heavy structural demolition during radiological decommissioning (e.g. the reactor building may be impaired because walls will be removed in order to gain access to radioactive piping and the reactor vessel, making the remaining structure unsafe), the safety of remaining buildings should not be affected. There has not been an expression of regulatory interest in removing non-radioactive structures. When the NRC responded to comments on the draft regulations for decommissioning, it specifically stated that, "[T]he use made of the facility after termination of the NRC license is independent of the alternative used to decommission the facility. With regard to reuse of the site for nuclear purposes, there is nothing in this rule preventing such reuse." [8]/ This statement, taken together with the fact that decommissioning only extends to contaminated structures, implicitly allows the reuse of remaining buildings.

It is my opinion that most utilities will not choose to abandon sites that have been used for nuclear power. This opinion is based on the economic issues implicit in abandoning real estate that is owned by the utility, abandoning the infrastructure that was built up to support the facility (e.g. roads, housing and transmission facilities), and abandoning the significant investments which have already gone into such structures as cooling towers and cooling water intake

[8]/ See "Preamble to Decommissioning Regulations", Federal Register, p. 24020, July 27, 1988.

structures. [9] These sites are valuable resources and will likely be used far into the future. Furthermore, new draft-proposed regulations on site release criteria actually redefine decommissioning to allow for restricted use of a facility. [10] This would have the effect of encouraging utilities to use the non-radiological portions of the facilities for re-use as industrial or power generation purposes.

Therefore, I recommend that should PP&L request inclusion of demolition of the non-radioactive structures, it be required to present a detailed analysis of the costs and benefits of all the options for using the property and the non-radioactive structures and that this study undergo a public review by the Commission Staff and interested parties. In this analysis, structures that are clearly unusable because of structural damage during radiological decommissioning should be identified and the costs should be included in the decommissioning cost estimate.

Q: Has similar treatment of the removal of non-radioactive structures and facilities been ordered in any recent decisions in other jurisdictions?

A: Yes. In a recent Illinois case, the Illinois regulatory body found that: [11]

> Based upon the evidence in the record, the Commission denies any funds to return sites to greenfield status. The burden is on the Company to prove that it will not re-use old structures. The Company has failed to convince the Commission that nonradioactive structures will not be used in the future. The Commission cannot allow ratepayers to pay for returning facilities to greenfield status when, in fact, some facilities may be re-used.

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[9] This consideration is particularly applicable to the SSES site where the expensive Cowanesque water diversion system was required to make the site fully usable for Susquehanna. This makes the site more valuable as a generating facility location.

[10] Proposed Rule, NRC, 10CFR Parts 20, 30, 40, 50, 51, 70, and 72, "Radiological Criteria for Decommissioning," 59FR43200, August 22, 1994.

[11] January 9, 1995 Order, State of Illinois, Illinois Commerce Commission, Commonwealth Edison Company, Proposed General Increase in Electric Rates, No. 94-0065.

> In addition, this Commission does not have a statutory obligation to return sites to greenfield status. Illinois law mandates that decommissioning trusts be established to fund the costs of decommissioning. However, it does not require that sites be returned to greenfield status. It is also clear from the evidence in the record that the NRC does not mandate greenfield status.

Q: Have there been any examples of nuclear power stations that have used non-contaminated buildings?

A: Yes. Converting a nuclear station to another power generation facility is an option that has been or is being used by a number of utilities, to make use of the infrastructure, water facilities and transmission capabilities. The Pathfinder research reactor, which was owned and operated by Northern States Power, was converted from nuclear generation to fossil-fuel fired generation after decontamination and separation of several of the nuclear components. Public Service of Colorado is currently converting the Fort St. Vrain commercial reactor to a fossil-fuel fired facility. Furthermore, the owners of both the Midland and Zimmer nuclear power plants, which had been nearly completed, were converted to fossil-fuel power production. Significant portions of the original equipment were utilized at both facilities. The Zimmer conversion, for example, was predicated on "the maximum use of the existing (nuclear) equipment" and used a major part of the original turbine, as well as "the original condenser, feedwater heaters, cooling tower, and most other balance of plant equipment" as well as many of the structures. [12]/ The Midland conversion also utilized similar portions of the balance of plant as it had been designed for nuclear use. Even at Shippingport, the largest American reactor that has been decommissioned up to this point, where it was reported that a "greenfield" approach to decommissioning

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[12]/ See article from *Power* Magazine, "World's First Nuclear-To-Coal Conversion A Success," April 1992, appended as **Exhibit DGB-2**.

was implemented, (that is, removing all buildings and returning the site to its original state), this was not the case. This plant was owned by the Department of Energy, although adjacent to Beaver Valley Units 1 and 2. Its decommissioning was intended to make the station safe from a radiation standpoint; to demonstrate safe and effective dismantlement of the facility; and to provide useful reference data for future decommissioning efforts. As can be seen in Figure 1 of **Exhibit DGB-3**, the turbine building, the pump house, water intake and discharge systems, the training center, and the auxiliary building were left standing after release of the site. At other plants in the country that we have direct experience with, facilities such as the water reclamation facility and the reactor training center have also been excluded from the decommissioning cost estimate.

Q: How did the Company decide which non-contaminated facilities it should demolish?

A: The decision seems to be based upon a recommendation by TLG Engineering. PP&L did not undertake a detailed evaluation, nor did it provide us with any decision making documentation. [13]/

Q: Are there any costs for removing non-contaminated items that should be included in the decommissioning estimate?

A: Yes. TLG refers to these costs as "cascading costs," which are defined as the costs associated with removing non-radioactive releasable materials in support of the decommissioning process. For example, the costs of removing a non-contaminated floor to gain access to a contaminated area is considered a cascading cost. These costs are described in the TLG cost estimate [14]/ and

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[13]/ Response to OCA-VIII-11. Included in **Exhibit DGB-4**.

[14]/ See Exhibit TSL-1, p. 4-12.

should be included in the radiological cost estimate, as they are.

Q: Do you have other recommendations regarding non-radiological decommissioning costs?

A: Yes. Should the Company decide to request inclusion of this portion of the plant in the future, I recommend that it present a detailed analysis of the costs and benefits of all the options for using the property and the non-radioactive structures and that this study undergo a public review under the normal regulatory process.

D. REASONABLENESS OF A CONTINGENCY

Q: What contingency factor is incorporated into the estimate?

A: The estimate includes a range of contingency factors to the different tasks which results in a total contingency of approximately 18% based on the overall estimate. Contingencies range by decommissioning task from 10% to 75%. [15]/ The radiological portion of the estimate includes an overall contingency of approximately 19%.

Q: Please define a contingency.

A: There is no agreed upon definition of contingency that specifies all items that should be included in a decommissioning estimate. Contingency generally is defined by the American Association of Cost Engineers as: "The specific provision for unforeseeable elements of cost within the defined project scope." [16]/ It is an allowance for costs that may occur, but are not included in the

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[15]/ Response to OCA-II-10. Included in **Exhibit DGB-5**.

[16]/ AIF/NESP-036, May 1986, pp. 13-1, 13-2.

estimate. Generally a contingency factor would include: minor changes in scope; allowance for uncertainties; allowance for untried processes, and unexpected job conditions.

Q: Should the Company use a specified percent contingency factor for decommissioning?

A: No. As contingency factors are used in construction and decommissioning cost estimates, they are intended to cover all uncertainties which the estimator cannot anticipate. Said another way, using a contingency factor implies that the risks of potential uncertainties will increase the ultimate cost of decommissioning. However, assumptions embedded within the decommissioning cost estimates, and additional assumptions concerning inflation and earnings rate assumptions, could change the direction of the risks. In effect, the costs could be lower than estimated.

The most significant uncertainty in the SSES estimate is the ultimate cost of low level radioactive waste disposal. Other uncertainties include: the decommissioning method ultimately chosen by the utility; how reductions in occupational exposure rates will affect costs; how unavailability of space for high-level waste will affect costs; to what extent the utility industry, and specifically PP&L , will be more efficient because of experience; how financial factors such as inflation rates for decommissioning and earnings rates on trust funds will affect the ultimate amount in the trust fund; and, over what period of time funds are to be collected. I acknowledge that some of these uncertainties could also drive costs upwards. However, I do not believe it is sound engineering practice, or sound regulatory policy, to blindly incorporate the costs of these uncertainties until more is known.

The reasons for this are explained further below.

1. **Low-level Radioactive Waste Disposal (LLRW) Costs.**

Waste burial accounts for almost 27 percent of the total cost of the Susquehanna decommissioning cost estimate. PP&L used the Barnwell, S.C. waste burial cost of approximately $279 per cubic foot of waste for the year 1993. This is based on waste burial costs that include surcharges of $220 per cubic foot. [17]/ Such surcharges are no longer in use or applicable to SSES. After June 1994, South Carolina closed its Barnwell facility to out-of-compact states. [18]/ Unit waste-burial cost forecasts are extremely speculative at the present time. In a Michigan review, we have seen cost estimates for LLRW that range from $91 per cubic foot to over $1300 per cubic foot. [19]/ A 1990 GAO report stated that after 1993, LLRW disposal costs could range from $50 to $590 per cubic foot. [20]/ TLG has assumed a base rate of $36.87 per cubic foot to $441 per cubic foot in other estimates produced between 1989 and 1994. [21]/ In its recent draft estimates, PNL included a sensitivity study and evaluated costs ranging from $50 per cubic ft. to $1000 per cu. ft. While these wide ranges of uncertainties emphasize the speculative nature of LLRW disposal costs at this time, they do not, in my opinion, justify the use of a fictitious unit disposal cost that is further inflated by contingency adders.

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[17]/ OCA Cross Examination Exhibit 17 (OCA-II-16).

[18]/ The Barnwell facility will now only accept waste from states in the Southeastern Compact, which include: Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, Tennessee and Virginia, and out of compact surcharges are no longer applied.

[19]/ See **Exhibit DGB-6**, Affidavit of James Cleary, Commissioner of Michigan Low-Level Radioactive Waste Authority.

[20]/ See **Exhibit DGB-7**, GAO/RCED-90-171, p.5.

[21]/ Response to OCA-II-4. Included in **Exhibit DGB-8**.

The current large amount of uncertainty is partially due to the failure of the Low-Level Waste Policy Act of 1980, and subsequent amendments in 1985. By this act, states were encouraged to form compacts in order to set up and finance regional LLRW disposal sites. As of early 1988, most states had joined regional compacts. At present there are approximately 15 compacts. However, only two compacts have designated a new site, and they are not expected to be accepting waste for some time. Under current law, the new sites will only be available to compact members. Without a site, and not being able to anticipate how many sites will be available, it is especially difficult to predict the eventual cost of LLRW disposal. However, this may only be a problem for performing estimates now, and by the time the SSES decommissioning waste is ready for disposal, the problem should have been resolved. [22/]

While no facility is currently cited in Pennsylvania, the state has joined an interstate compact (the Appalachian States Compact) to provide for disposal of LLRW, and met the required milestones in 1986 and 1988. Pennsylvania was selected as the host state for the disposal site, but progress on the facility has been slow, and the Compact is still in the site identification phase. [23/]

Furthermore, in all jurisdictions that I have studied, waste generators are required to pay for most of the front-end costs for a LLRW burial facility. PP&L has already paid nearly $6 million of a total of $33 million being collected from Pennsylvania nuclear utilities. [24/] These costs may include all pre-construction costs, including siting, environmental reports, preliminary design, licensing fees and administrative costs for the Compact. The estimated LLRW burial cost cited

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22/ The first SSES decommissioning waste is not expected until approximately 2025.

23/ OCA Cross Examination Exhibit 15 (OCA II-14).

24/ Response to OCA-X-4, included in **Exhibit DGB-9**.

at the beginning of this section, include some or all of these costs. Therefore, in order to arrive at a more precise estimate of the cost for a utility to dispose of LLRW at the time of decommissioning, some or all of the front-end fixed costs would have to be excluded. While I do not recommend doing so in this case, I think that the above stated concern adds large a degree of conservatism to the adjusted estimate.

In addition, the estimate for LLRW disposal includes an estimate of the cost of disposing of greater-than-class-C (GTCC) wastes. These wastes are the highly activated materials which the federal government will most likely take responsibility for, and will be disposed of in a geologic repository. The calculation for disposal costs is based on an equivalent to that charged for spent-fuel disposal. [25/] The problem with this method is that it assumes that all GTCC wastes would have the same specific activity as spent fuel, which is not the case. The ultimate disposal cost will, in my opinion, be somewhat less. This cost is not insignificant: over $11 million is estimated for the disposal of GTCC wastes.[26/]

25/ OCA Cross Examination Exhibit 17 (OCA-II-16) and OCA Cross Examination Exhibit 18 (OCA-II-17, Attachment 1).

26/ See TSL-2, page 6-3.

2. Decommissioning Method

The estimate assumes that the plant will undergo the DECON option ("immediate" dismantling), and TLG has estimated that this is less expensive than SAFSTOR. The choice of the decommissioning method should consider several factors. The first priority should be protecting public health and safety (including occupational exposure). Clearly, there would be less occupational exposure involved in plant decommissioning after radioactive decay for 50 years.

Another consideration will be the availability of space and the cost of disposal for LLRW. As discussed above, LLRW disposal costs are one of the biggest uncertainties and cost elements in decommissioning. The Company can affect this uncertainty by reducing the amount of waste. There would be significant decreases in the activity of the low-level radioactive waste if a facility is placed in SAFSTOR for 50 years before undergoing dismantlement. If waste burial costs increase significantly, the SAFSTOR option increases its attractiveness.

3. The Effects of Technology Development and Experience on Decommissioning Costs.

As experience is gained in decommissioning, methods likely will be developed to reduce costs. For example, the estimates now assume that pipe will be cut into 7 foot lengths for disposal, although it may be more efficient to use longer lengths. Quadrex and SEG, waste reduction and packaging contractors, both accept up to 40 foot segments. The new PNL estimates include 15 ft cuts. Another example is that the new PNL estimates assume concrete removal to a depth of one inch, as opposed to two inches in previous estimates. This reduces both labor and LLRW disposal costs. The industry, in its comments to the NRC on the draft PNL estimate, claim the one inch may be conservative, and washing will suffice. [27]/ Yet another example is that there is no rule that requires spent fuel to be stored for five years in wet storage. Although it would still have to be stored for five years prior to acceptance by DOE, it could be stored in dry casks. Several cask manufacturers are working on a cask to take spent-fuel that is not cooled for five years. [28]/ This product would shorten the delay time which TLG has incorporated into its estimate.

Additionally, it should also be noted that the Shippingport decommissioning project, the largest reactor to be completely decommissioned in the U.S., cost about 8% less than the cost estimates. [29]/

4. License extension

There has been much discussion in the nuclear industry of extending the life of plants for twenty or more years beyond their existing licenses (present licenses are 30-40 years). Although PP&L has no official plans to do so, [30]/ this would have the effect of spreading payments out over a longer period of time, thus reducing the annual payments.

5. Other reasons

One of the most compelling reasons for removing the contingency rate is

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[27]/ February 15, 1994 comments on the PNL Draft Report submitted by the Nuclear Management and Resources Council, p. 8.

[28]/ TLG Response to Cities RFI-09-018, Gulf States Utilities Company, Docket No. 12852, Texas Public Utilities Commission, 1994.

[29]/ DOE/SSDP-0081, Shippingport Station Decommissioning Project, Final Project Report, p. 6, December 1989. See **Exhibit DGB-10** for excerpt.

[30]/ Response to OTS Data Request, OTS-RB-37. Included in **Exhibit DGB-11**.

that most states and the NRC require that cost estimates be periodically updated and thus new versions should be able to capture much of the technical and economic uncertainties.

Another reason is that the TLG contingency factors are based on data that was developed in 1985-86, much of which was based on earlier experience. [31] There has been some smaller decommissioning experience, as well as major maintenance, which should add to the data on what is really needed. This experience will be greatly expanded through the actual decommissioning of large nuclear units that is just now getting underway. Much learning will have been accomplished long before the SSES decommissioning will begin.

Q: Taking all of the above factors into consideration, what adjustments do you recommend be made to the SSES decommissioning cost estimate for this case?

A: First of all, given that no studies or planning have been performed by PP&L as to future site use, I recommend that all of the non-radiological facility removal costs be excluded. Further, as described above, because there is much uncertainty present in the LLRW unit costs, and because of other contingency inherent in the radiological removal cost estimate, I recommend that all of the specific contingency adders be removed from the radiological costs. Removal of the radiological contingency can be considered to be a proxy for the total amount of uncertainty, which could drive the costs either higher or lower.

Q: Please explain how your adjustment should be made.

A: The TLG cost estimate is segregated into three distinct periods. Period 1 covers the initial planning and preparation work. Period 2 covers the work of removal of

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[31]/ Response to OCA- II-10. Included in **Exhibit DGB-5**.

the radiological equipment and materials, and Period 3 covers the removal of the non-radiological facilities. [32]/ **Exhibit DGB-12** shows my adjustments to the TLG estimate, in which I have removed all of the Period 3 costs, as well as the contingency factors for Periods 1 and 2. The specific costs in millions are as follows:

	Total	Contingency	Contingency %
Period 1 (Planning)	$68.704	$9.074	15.2
Period 2 (Radiological Removal)	$610.877	$97.495	19.3
Period 3 (Non-Radiological)	$124.679	$16.235	15.0
TOTAL	**$804.260**		

I recommend removing all of the Period 3 cost ($124.679 million), the Period 1 Contingency ($9.074 million), and the Period 2 Contingency ($97.495 million). My total adjustment amounts to a reduction of $231.248 million to the TLG total of $804.260 million, for a net estimate for both units of $573.012 million

[32]/ A small portion of the non-radiological facility is removed during Period 2 to make possible the access to radioactive components. Thus, the non-radiological costs are not entirely encompassed by the Period 3 effort. The effect of this on the overall cost allocation is very small (less than 1/2%) and has been disregarded so as to simplify the adjustment process.

IV. CONCLUSIONS & RECOMMENDATIONS

Q: Would you please summarize your conclusions?

A: My testimony conclusions regarding the nuclear decommissioning of the SSES are:

1) The decommissioning cost estimate should be reduced by $124.679 million so as to remove the non-radiological cost element.
2) The contingency amounts, $106.569 million, should be removed from the radiological cost element so as to compensate for the excess and unjustified LLRW disposal unit costs used in the estimate.
3) Close monitoring of PP&L's stated plan to review and adjust the decommissioning cost estimate at two year intervals should be performed.

Q: Does that conclude your testimony?

A: Yes it does.

LIST OF EXHIBITS

No.	Subject
DGB-1	Resume of Dale G. Bridenbaugh
DGB-2	Article from *Power* Magazine, "World's First Nuclear-To-Coal Conversion A Success," April 1992
DGB-3	Figure 1 - Turbine Building, Pump House, Water Intake and Discharge Systems, Training Center, and Auxiliary Building
DGB-4	Response to OCA-VIII-11
DGB-5	Response to OCA-II-10
DGB-6	Affidavit of James Cleary, Commissioner of Michigan Low-level Radioactive Waste Authority
DGB-7	GAO/RCED-90-171, p. 5
DGB-8	Response to OCA-II-4
DGB-9	Response to OCA-X-4
DGB-10	DOE/SSDP-0081, Shippingport Station Decommissioning Project, Final Project Report, p. 6, December 1989
DGB-11	Response to OTS-RB-37.
DGB-12	Adjustments to SSES Decommissioning Cost

EXHIBIT DGB-1

RESUME OF DALE G. BRIDENBAUGH

PROFESSIONAL QUALIFICATIONS OF DALE G. BRIDENBAUGH

DALE G. BRIDENBAUGH
MHB Technical Associates
1723 Hamilton Avenue
Suite K
San Jose, California 95125
(408) 266-2716

EXPERIENCE:

1976 - PRESENT

President - MHB Technical Associates, San Jose, California

Co-founder and partner of technical consulting firm. Specialists in energy consulting to governmental and other groups interested in evaluation of nuclear plant safety and licensing. Consultant in this capacity to state agencies in California, New York, Illinois, New Jersey, Pennsylvania, Oklahoma and Minnesota and to the Norwegian Nuclear Power Committee, Swedish Nuclear Inspectorate, and various other organizations and environmental groups. Performed extensive safety analysis for Swedish Energy Commission and contributed to the Union of Concerned Scientists Review of WASH-1400. Consultant to the U.S. NRC - LWR Safety Improvement Program, performed Cost Analysis of Spent Fuel Disposal for the Natural Resources Defense Council, and contributed to the Department of Energy LWR Safety Improvement Program for Sandia Laboratories. Served as expert witness in NRC and state utility commission hearings.

1976 - (FEBRUARY - AUGUST)

Consultant, Project Survival, Palo Alto, California

Volunteer work on Nuclear Safeguards Initiative campaigns in California, Oregon, Washington, Arizona, and Colorado. Numerous presentations on nuclear power and alternative energy options to civic, government, and college groups. Also resource person for public service presentations on radio and television.

1973 - 1976

Manager, Performance Evaluation and Improvement, General Electric Company - Nuclear Energy Division, San Jose, California

Managed seventeen technical and seven clerical personnel with responsibility for establishment and management of systems to monitor and measure Boiling Water Reactor equipment and system operational performance. Integrated General Electric resources in customer plant modifications, coordinated correction of causes of forced outages and of efforts to improve reliability and performance of BWR systems. Also responsible for development of Division Master Performance Improvement Plan as well as for numerous Staff special assignments on long-range studies. Was on special assignment for the management of two different ad hoc projects formed to resolve unique technical problems.

1972 - 1973

Manager, Product Service, General Electric Company - Nuclear Energy Division, San Jose, California

Managed group of twenty-one technical and four clerical personnel. Prime responsibility was to direct interface and liaison personnel involved in corrective actions required under contract warranties. Also in charge of refueling and service planning, performance analysis, and service communication functions supporting all completed commercial nuclear power reactors supplied by General Electric, both domestic and overseas (Spain, Germany, Italy, Japan, India, and Switzerland).

1968 - 1972

Manager, Product Service, General Electric Company - Nuclear Energy Division, San Jose, California

Managed sixteen technical and six clerical personnel with the responsibility for all customer contact, planning and execution of work required after the customer acceptance of department-supplied plants and/or equipment. This included quotation, sale and delivery of spare and renewal parts. Sales volume of parts increased from $1,000,000 in 1968 to over $3,000,000 in 1972.

1966 - 1968

Manager, Complaint and Warranty Service, General Electric Company - Nuclear Energy Division, San Jose, California

Managed group of six persons with the responsibility for customer contacts, planning and execution of work required after customer acceptance of department-supplied plants and/or equipment--both domestic and overseas.

1963 - 1966

Field Engineering Supervisor, General Electric Company, Installation and Service Engineering Department, Los Angeles, California

Supervised approximately eight field representatives with responsibility for General Electric steam and gas turbine installation and maintenance work in Southern California, Arizona, and Southern Nevada. During this period was responsible for the installation of eight different central station steam turbine-generator units, plus much maintenance activity. Work included customer contact, preparation of quotations, and contract negotiations.

1956 - 1963

Field Engineer, General Electric Company, Installation and Service Engineering Department, Chicago, Illinois

Supervised installation and maintenance of steam turbines of all sizes. Supervised crews of from ten to more than one hundred men, depending on the job. Worked primarily with large utilities but had significant work with steel, petroleum and other process industries. Had four years of experience at construction, startup, trouble-shooting and refueling of the first large-scale commercial nuclear power unit.

1955 - 1956

Engineering Training Program, General Electric Company, Erie, Pennsylvania, and Schenectady, New York

Training assignments in plant facilities design and in steam turbine testing at two General Electric factory locations.

1953 - 1955

United States Army - Ordnance School, Aberdeen, Maryland

Instructor - Heavy Artillery Repair. Taught classroom and shop disassembly of artillery pieces.

1953

Engineering Training Program, General Electric Company, Evendale, Ohio

Training assignment with Aircraft Gas Turbine Department.

EDUCATION & AFFILIATIONS:

BSME - 1953, South Dakota School of Mines and Technology, Rapid City, South Dakota. Upper 1/4 of class.

Professional Nuclear Engineer - California. Certificate No. 0973.

Member - American Nuclear Society

Various Company Training Courses during career including Professional Business Management, Kepner Tregoe Decision Making, Effective Presentation, and numerous technical seminars.

HONORS & AWARDS:

Sigma Tau - Honorary Engineering Fraternity.

General Managers Award, General Electric Company.

PUBLICATIONS & TESTIMONY OF DALE G. BRIDENBAUGH:

1. Operating and Maintenance Experience, presented at Twelfth Annual Seminar for Electric Utility Executives, Pebble Beach, California, October 1972, published in General Electric NEDC-10697, December 1972.

2. Maintenance and In-Service Inspection, presented at IAEA Symposium on Experience From Operating and Fueling of Nuclear Power Plants, Bridenbaugh, Lloyd & Turner, Vienna, Austria, October, 1973.

3. Operating and Maintenance Experience, presented at Thirteenth Annual Seminar for Electric Utility Executives, Pebble Beach, California, November 1973, published in General Electric NEDO-20222, January 1974.

4. Improving Plant Availability, presented at Thirteenth Annual Seminar for Electric Utility Executives, Pebble Beach, California, November 1973, published in General Electric NEDO-20222, January, 1974.

5. Application of Plant Outage Experience to Improve Plant Performance, Bridenbaugh and Burdsall, American Power Conference, Chicago, Illinois, April 14, 1974.

6. Nuclear Valve Testing Cuts Cost, Time, Electrical World, October 15, 1974.

7. Testimony of D. G. Bridenbaugh, R. B. Hubbard, and G. C. Minor before the United States Congress, Joint Committee on Atomic Energy, February 18, 1976, Washington, D.C. (Published by the Union of Concerned Scientists, Cambridge, Massachusetts.)

8. Testimony of D. G. Bridenbaugh, R. B. Hubbard, and G. C. Minor to the California State Assembly Committee on Resources, Land Use, and Energy, March 8, 1976.

9. Testimony by D. G. Bridenbaugh before the California Energy commission, entitled, Initiation of Catastrophic Accidents at Diablo Canyon, Hearings on Emergency Planning, Avila Beach, California, November 4, 1976.

10. Testimony by D. G. Bridenbaugh before the U. S. Nuclear Regulatory Commission, subject: Diablo Canyon Nuclear Plant Performance, Atomic Safety and Licensing Board Hearings, in the matter of Pacific Gas and Electric Company, (Diablo Canyon Nuclear Power Plant, Units 1 and 2), Docket Nos. 50-275-OL, 50-323-OL,December, 1976.

11. Testimony by D. G. Bridenbaugh before the California Energy Commission, subject: Interim Spent Fuel Storage Considerations, March 10, 1977.

12. Testimony of D. G. Bridenbaugh before the New York State Public Service Commission Siting Board Hearings concerning the Jamesport Nuclear Power Station, subject: Effect of Technical and Safety Deficiencies on Nuclear Plant Cost and Reliability, in the matter of Long Island Lighting Company (Jamesport Nuclear Power Station, Units 1 and 2), Case No. 80003, April, 1977.

13. Testimony by D. G. Bridenbaugh before the California State Energy Commission, subject: Decommissioning of Pressurized Water Reactors, Sundesert Nuclear Plant Hearings, in the matter of San Diego Gas and Electric Company (Notice of Intention to File Application for Certification of Site and Related Facilities), Docket No. 76-NOI-2, June 9, 1977.

14. Testimony by D. G. Bridenbaugh before the California State Energy Commission, subject: Economic Relationships of Decommissioning, Sundesert Nuclear Plant, for the Natural Resources Defense Council, in the matter of San Diego Gas and Electric Company: Notice of Intention to File Application for Certification of Site and Related Facilities, Docket No. 76-NOI-2,July 15, 1977.

15. The Risks of Nuclear Power Reactors: A Review of the NRC Reactor Safety Study WASH-1400, Kendall, Hubbard, Minor & Bridenbaugh, et. al., for the Union of Concerned Scientists, August, 1977.

16. Testimony by D. G. Bridenbaugh before the Vermont State Board of Health, subject: Operation of Vermont Yankee Nuclear Plant and Its Impact on Public Health and Safety, October 6, 1977.

17. Testimony by D. G. Bridenbaugh before the U.S. Nuclear Regulatory Commission, Atomic Safety and Licensing Board, subject: Deficiencies in Safety Evaluation of Non-Seismic Issues, Lack of a Definitive Finding of Safety, Diablo Canyon Nuclear Units, October 18, 1977, Avila Beach, California.

18. Testimony by D. G. Bridenbaugh before the Norwegian Commission on Nuclear Power, subject: Reactor Safety/Risk, October 26, 1977.

19. Swedish Reactor Safety Study: Barseback Risk Assessment, MHB Technical Associates, January, 1978. (Published by the Swedish Department of Industry as Document Dsl 1978:1)

20. Testimony by D. G. Bridenbaugh before the Louisiana State Legislature Committee on Natural Resources, subject: Nuclear Power Plant Deficiencies Impacting on Safety & Reliability, Baton Rouge, Louisiana, February 13, 1978.

21. Spent Fuel Disposal Costs, report prepared by D. G. Bridenbaugh for the Natural Resources Defense Council (NRDC), August 31, 1978.

22. Testimony of D. G. Bridenbaugh, G. C. Minor, and R. B. Hubbard before the Atomic Safety and Licensing Board, in the matter of the Black Fox Nuclear Power Station Construction Permit Hearings, September 25, 1978, Tulsa, Oklahoma.

23. Testimony of D. G. Bridenbaugh and R. B. Hubbard before the Louisiana Public Service Commission, Nuclear Plant and Power Generation Costs, November 16, 1978, Baton Rouge, Louisiana.

24. Testimony by D. G. Bridenbaugh before the City Council and Electric Utility Commission of Austin, Texas, Design, Construction, and Operating Experience of Nuclear Generating Facilities, December 5, 1978, Austin, Texas.

25. Testimony by D. G. Bridenbaugh for the Commonwealth of Massachusetts, Department of Public Utilities, Impact of Unresolved Safety Issues, General Deficiencies, and Three Mile Island-Initiated Modifications on Power Generation Cost at the Proposed Pilgrim-2 Nuclear Plant, June 8, 1979.

26. Improving the Safety of LWR Power Plants, MHB Technical Associates, prepared for U.S. Dept. of Energy, Sandia Laboratories, September 28, 1979.

27. BWR Pipe and Nozzle Cracks, MHB Technical Associates, for the Swedish Nuclear Power Inspectorate (SKI), October, 1979.

28. Uncertainty in Nuclear Risk Assessment Methodology. MHB Technical Associates, for the Swedish Nuclear Power Inspectorate (SKI), January 1980.

29. Testimony of D. G. Bridenbaugh and G. C. Minor before the Atomic Safety and Licensing Board, in the matter of Sacramento Municipal Utility District, Rancho Seco Nuclear Generating Station following TMI-2 accident, subject: Operator Training and Human Factors Engineering, for the California Energy Commission, Docket No. 50-312-SP, February 11, 1980.

30. Italian Reactor Safety Study: Caorso Risk Assessment, MHB Technical Associates, for Friends of the Earth, Italy, March, 1980.

31. Decontamination of Krypton-85 from Three Mile Island Nuclear Plant, H. Kendall, R. Pollard, and D. G. Bridenbaugh, et al, The Union of Concerned Scientists, delivered to the Governor of Pennsylvania, May 15, 1980.

32. Testimony by D. G. Bridenbaugh before the New Jersey Board of Public Utilities, on behalf of New Jersey Public Advocate's Office, Division of Rate Counsel, Analysis of 1979 Salem-1 Refueling Outage, in the matter of the Petition of Public Service Electric and Gas Company for approval of an increase in Electric and Gas rates and for changes in the tariffs for Electric and Gas service, P.U.C. N.J. No. 7, Electric, and P.U.C. N.J. No. 5, Gas, Pursuant to R.S. 48:2-21, August 1980.

33. Minnesota Nuclear Plants Gaseous Emissions Study, MHB Technical Associates, for Minnesota Pollution Control Agency, September, 1980.

34. Position Statement, Proposed Rulemaking on the Storage and Disposal of Nuclear Waste, Joint Cross-Statement of Position of the New England Coalition on Nuclear Pollution and the Natural Resources Defense Council, September, 1980.

35. Testimony by D. G. Bridenbaugh and G. C. Minor, before the New York State Public Service Commission, in the matter of Long Island Light Company Temporary Rate Case, prepared for the Shoreham Opponents Coalition, September 22, 1980, Case No. 27774, Shoreham Nuclear Plant Construction Schedule.

36. Supplemental Testimony by D. G. Bridenbaugh before the New Jersey Board of Public Utilities, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Analysis of 1979 Salem-1 Refueling Outage, in the matter of the Petition of Public Service Electric and Gas Company for approval of an increase in Electric and Gas rates and for changes in the tariffs for Electric and Gas Service, P.U.C. N.J. No. 7, Electric, and P.U.C. N.J. No. 5, Gas, Pursuant to R.S. 48:2-21, Docket No. 794-310, OAL Docket No. PUL-877-79, December, 1980.

37. Testimony by D. G. Bridenbaugh and G. C. Minor, before the New Jersey Board of Public Utilities, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Oyster Creek 1980 Refueling Outage Investigation, in the matter of the Petition of Jersey Central Power and Light Company for approval of an increase in the rates for electrical service and adjustment clause and factors for such service, OAL Docket No. PUC-3518-80, BPU Docket Nos. 804-285, 807-488, February 1981.

38. Economic Assessment: Ownership Interest in Palo Verde Nuclear Station, MHB Technical Associates, for the City of Riverside, September 11, 1981.

39. Testimony of D. G. Bridenbaugh before the Public Utilities Commission of Ohio, in the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedules of the Toledo Edison Company and Related Matters, subject: Davis-Besse Nuclear Power Station 1980-81 Outage Review, Case No. 81-306-EL-EFL, November, 1981.

40. Supplemental Testimony of D. G. Bridenbaugh before the Public Utilities Commission of Ohio, in the matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of the Toledo Edison Company and Related Matters, subject: Davis-Besse Nuclear Power Station 1980-81 Outage Review, Case No. 81-306-EL-EFL, November 1981.

41. Systems Interaction and Single Failure Criterion, Phase 2 Report, MHB Technical Associates for the Swedish Nuclear Power Inspectorate (SKI), January, 1982.

42. Testimony of D. G. Bridenbaugh and G. C. Minor on behalf of Governor Edmund G. Brown Jr., before the Atomic Safety and Licensing Board, regarding Contention 10, Pressurizer Heaters, in the matter of Pacific Gas and Electric Company (Diablo Canyon Nuclear Power Plant, Units 1 and 2), Docket Nos. 50-275-OL, 50-323-OL, January 11, 1982.

43. Testimony of D. G. Bridenbaugh and G. C. Minor on behalf of Governor Edmund G. Brown Jr., before the Atomic Safety and Licensing Board, regarding Contention 12, Block and Pilot Operated Relief Valves, in the matter of Pacific Gas and Electric Company (Diablo Canyon Nuclear Power Plant, Units 1 and 2), Docket Nos. 50-275-OL, 50-323-OL, January 11, 1982.

44. Testimony of D. G. Bridenbaugh before the Commonwealth of Massachusetts, Department of Public Utilities, on behalf of the Massachusetts Attorney General, Pilgrim Nuclear Power Station, 1981-82 Outage Investigation, in the matter of Boston Edison Company, DPU Docket No. 1009-F, March 11, 1982.

45. Testimony of D. G. Bridenbaugh before the Pennsylvania Public Utility Commission, on behalf of the Pennsylvania Office of Consumer Advocate, Beaver Valley Outage, March, 1982.

46. Interim testimony of D. G. Bridenbaugh on Expected Lifetimes and Performance of Nuclear Power Plants, State of Illinois Commerce Commission, 82-0026, AG Exhibit 6, March, 1982.

47. Testimony of D. G. Bridenbaugh and G. C. Minor before the Atomic Safety and Licensing Board, on behalf of Suffolk County, in the matter of Long Island Lighting Company, Shoreham Nuclear Power Station, Unit 1, regarding Suffolk County Contention 11, Passive Mechanical Valve Failures, Docket No. 50-322-OL, April 13, 1982.

48. Testimony of D. G. Bridenbaugh and R. B. Hubbard, in the Matter of Jersey Central Power and Light Company For an Increase in Rates for Electrical Service, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Three Mile Island Units 1 & 2, Cleanup and Modification Programs, DPU Docket Nos. 818-726, 818-736, May, 1982.

49. Testimony of D. G. Bridenbaugh and G. C. Minor on behalf of Suffolk County, before the Atomic Safety and Licensing Board, in the matter of Long Island Lighting Company, Shoreham Nuclear Power Station, Unit 1, regarding Suffolk County Contention 22, SRV Test Program, Docket No. 50-322-OL, May 25, 1982.

50. Testimony of D. G. Bridenbaugh and G. C. Minor on behalf of Suffolk County, before the Atomic Safety and Licensing Board, in the matter of Long Island Lighting Company, Shoreham Nuclear Power Station, Unit 1, regarding Suffolk County Contention 28(a)(vi) and SOC Contention 7A(6), Reduction of SRV Challenges, Docket No. 50-322-OL, June 14, 1982.

51. Testimony of D. G. Bridenbaugh before the Illinois Commerce Commission, on behalf of the Illinois Attorney General's Office, Expected Lifetimes and Performance of Nuclear Power Plants, in the matter of Commonwealth Edison (Proposed general increase in electric rates), ICC Docket No. 82-0026, June 18, 1982.

52. Testimony of D. G. Bridenbaugh and R. B. Hubbard on behalf of the Ohio Consumers Counsel, before the Public Utilities Commission of Ohio, regarding Construction of Perry Nuclear Generating Unit No. 1, in the matter of the application of the Cleveland Electric Illuminating Company for authority to amend and increase certain of its filed schedules fixing rates and charges for electric service, Case No. 81-1378-EL-AIR, October 7, 1982.

53. Issues Affecting the Viability and Acceptability of Nuclear Power Usage in the United States, prepared by MHB Technical Associates for Congress of the United States, Office of Technology Assessment for use in conjunction with Workshop on Technological and Regulatory Changes in Nuclear Power, December 8 & 9, 1982.

54. Testimony of D. G. Bridenbaugh on behalf of Rockford League of Women Voters, before the Atomic Safety and Licensing Board, in the matter of Commonwealth Edison Company, Byron Station, Units 1 and 2, regarding Contention 22, Steam Generators, Docket Nos. 50-454, 50-455, March 1, 1983.

55. Testimony of G. C. Minor and D. G. Bridenbaugh before the Pennsylvania Public Utility Commission, on behalf of the Office of Consumer Advocate, Regarding the Cost of Constructing the Susquehanna Steam Electric Station, Unit I, Re: Pennsylvania Power and Light, Docket No. R-822169, March 18, 1983.

56. Surrebuttal Testimony of D. G. Bridenbaugh before the Pennsylvania Public Utility Commission, on behalf of the Office of Consumer Advocate, Regarding the Cost of Constructing the Susquehanna Steam Electric Station, Unit I, Re: Pennsylvania Power and Light, Docket No. R-822169, April 20, 1983.

57. Testimony of D. G. Bridenbaugh In the Matter of Public Service Gas & Electric, Base Rate Case, Nuclear Construction Expenditures, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Docket No. 836-620, OAL Docket No. PUC-04930-83, October 13, 1983.

58. Affidavit of D. G. Bridenbaugh, in the Matter of Jersey Central Power and Light, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, TMI Fault Investigation, DPU Docket No. 836-500, November 23, 1983.

59. Testimony of D. G. Bridenbaugh, in the Matter of Public Service Electric & Gas, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, LEAC Investigation, Salem-1 Outages, DPU Docket No. 831-25, December 1, 1983.

60. Rebuttal Testimony of D. G. Bridenbaugh, in the Matter of Public Service Electric & Gas, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, LEAC Investigation, Salem-1 Outages, DPU Docket No. 831-25, January 18, 1984.

61. Testimony of D. G. Bridenbaugh, L. M. Danielson, R. B. Hubbard and G. C. Minor before the State of New York Public Service Commission, PSC Case No. 27563, in the matter of Long Island Lighting Company Proceeding to Investigate the Cost of the Shoreham Nuclear Generating Facility -- Phase II, on behalf of County of Suffolk, February 10, 1984.

62. Testimony of D. G. Bridenbaugh, in the Matter of Jersey Central Power & Light Company, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Base Rate Case, Oyster Creek 1983-84 Outage and O&M and Capital Expenditures, OAL Docket No. PUL-00797-84, BPU Docket No. 841-55, May 23, 1984.

63. Direct Testimony of Dale G. Bridenbaugh and Richard B. Hubbard, Before the Illinois Commerce Commission, Illinois Power Company, Clinton Nuclear Station, on its own motion, an investigation to consider a plan for moderating the initial rate increase associated with placing Illinois Power Company's Clinton Unit No. 1 generating station in service, Docket No. 84-0055, available from Illinois Governor's Office of Consumer Services, July 30, 1984.

64. Joint Direct Testimony of Dr. Robert N. Anderson, Professor Stanley G. Christensen, G. Dennis Eley, Dale G. Bridenbaugh and Richard B. Hubbard Regarding Suffolk County's Emergency Diesel Generator Contentions, Before the Atomic Safety and Licensing Board, in the matter of Long Island Lighting Company, Shoreham Nuclear Plant Unit 1, NRC Docket No. 50-322-OL, July 31, 1984.

65. Surrebuttal Testimony of Dale G. Bridenbaugh, Lynn M. Danielson, Richard B. Hubbard, and Gregory C. Minor, Before the New York State Public Service Commission, PSC Case No. 27563, Shoreham Nuclear Station, Long Island Lighting Company, on behalf of Suffolk County and New York State Consumer Protection Board, in the matter of Long Island Lighting Company Proceeding to Investigate the cost of the Shoreham Nuclear Generating Facility - Phase II, October 4, 1984.

66. Direct Testimony of Dale G. Bridenbaugh, Lynn M. Danielson and Gregory C. Minor on Behalf of Massachusetts Attorney General, DPU 84-145, Before the Massachusetts Department of Public Utilities, regarding the prudency of expenditures by Fitchburg Gas and Electric Light Company on Seabrook Unit 2, November 23, 1984, 84 pp.

67. Direct Testimony of Dale G. Bridenbaugh, Richard B. Hubbard and Lynn K. Price on Behalf of Massachusetts Attorney General, DPU 84-152, Before the Massachusetts Department of Public Utilities, regarding the investigation by the Department of the Cost and Schedule of Seabrook Unit 1, December 12, 1984.

68. Direct Testimony of Dale G. Bridenbaugh, Lynn M. Danielson and Gregory C. Minor on Behalf of Maine Public Utilities Commission Staff regarding Seabrook Unit 2, Docket No. 84-113, December 21, 1984.

69. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor Regarding Suffolk County's Emergency Diesel Generator Load Contention, Docket No. 50-322-OL, January 25, 1985.

70. Direct Testimony of Dale G. Bridenbaugh, in the Matter of the Motion of Public Service Electric & Gas, on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Motion To Increase The Level of the Levelized Energy Adjustment Clause, Docket No. ER 8501166 and Docket No. 837-620, April 24, 1985.

71. Direct Testimony of Dale G. Bridenbaugh on behalf of the Attorney General of the Commonwealth of Massachusetts, in the Matter of Boston Edison Company DPU 85-1B, A Hearing to Determine Whether Fuel and Purchased Power Costs Associated with the Outage at Pilgrim Nuclear Power Station Which Began on December 10, 1983 and Ended on December 30, 1984 Were Reasonably and Prudently Incurred. May 13, 1985.

72. Direct Testimony of Dale G. Bridenbaugh on behalf of the Residential Ratepayer Consortium, in the Matter of the Application of Consumers Power Company for a Power Supply Cost Reconciliation proceeding for the 12-month period ended December 13, 1984, regarding Palisades Outage Review, Case No. U-7785-R, August 28, 1985.

73. Direct Testimony of Dale G. Bridenbaugh, Lynn M. Danielson, and Gregory C. Minor on behalf of the Department of Public Service, State of Vermont Public Service Board Docket No. 5030, Central Vermont Public Service Corporation, November 11, 1985.

74. Direct Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, in the matter of JCP&L for an increase in rates, Base Rate Case, Oyster Creek O&M and Capital Expenditures, OAL Docket No. 4929-85, BPU Docket No. 8507-698, November 25, 1985.

75. Direct Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, in the matter of JCP&L, TMI-Restart - LEAC, Re: TMI-Restart Commercial Operation Standards & Reliability of Service, January 31, 1986.

76. Direct Testimony of Dale G. Bridenbaugh, Gregory C. Minor, Lynn K. Price, and Steven C. Sholly on behalf of State of Connecticut Department of the Public Utility Control Prosecutorial Division and Division of Consumer Counsel in the matter of Connecticut Light and Power Company Retrospective Audit of the Prudence of the Management and Financing of the Construction of Millstone Unit 3, February 18, 1986.

77. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of Massachusetts Attorney General regarding the prudence of expenditures by New England Power Co. on Seabrook Unit 2, Docket Nos. ER 85-646-000, ER 85-647-000, February 21, 1986.

78. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of Massachusetts Attorney General regarding WMECo Construction Prudence for Millstone Unit 3, in the matter of investigation by the department on it own motion as to the priority of the rates and charges set forth in schedules filed with the department Dec. 17, 1985 by Western Massachusetts Electric Co. to become effective Jan. 1, 1986, Docket No. 85-270, March 19, 1986.

79. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of Massachusetts Attorney General regarding WMECo's Commercial Operating Dates and Deferred Capital Additions on Millstone Unit 3, Docket No. 85-270, March 19, 1986.

80. Rebuttal Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of Massachusetts Attorney General regarding New England Power Company's Seabrook 2 Rebuttal, Docket Nos. ER 85-646-001, ER 85-647-001, April 2, 1986.

81. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of State of Maine Staff of Public Utilities Commission regarding Construction Prudence of Millstone Unit 3, in the matter of Maine Power Company Proposed Increase in Rates, Docket No. 85-212, April 21, 1986.

82. Direct Testimony of Dale G. Bridenbaugh and Peter M. Strauss on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, regarding Base Rate Case: In-Service Criteria for Hope Creek, Hope Creek O&M and Decommissioning Costs, and Operating Plant O&M Costs, OAL Docket No. PUL 0231-86, BPU Docket No. ER 85121163, May 19, 1986, 107 pp.

83. Direct Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, regarding Base Rate Case: Hope Creek Commercial Operating Date and Criteria, Hope Creek O&M Costs, Operating Life, Capital Additions, and Decommissioning Costs, in the matter of Atlantic City Electric Company increasing its rates for electric service - Phase II, OAL Docket No. PUL 3290-85, BPU Docket No. ER 8504-434, May 27, 1986, 85 pp.

84. Direct Testimony of Dale G. Bridenbaugh, Richard B. Hubbard, and Lynn K. Price on behalf of State of Illinois Office of the Attorney General and Office of Public Counsel, in the matter of Illinois Commerce Commission on its own motion, an investigation to consider a plan for moderating the initial rate increase associated with placing Illinois Power Company's Clinton Unit 1 generating station in service, Docket No. 84-0055, July 9, 1986.

85. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of the Vermont Department of Public Service, regarding Tariff Filing of Central Vermont Public Service Corporation Requesting a 12% Increase in Rates, Docket No. 5132, August 25, 1986.

86. Direct Testimony of Dale G. Bridenbaugh and Richard B. Hubbard on behalf of the Pennsylvania Office of Consumer Advocate, regarding Pennsylvania Public Utility Commission vs. Duquesne Light Company and Pennsylvania Power Company, Docket Nos. R-860378 and R-850267, September 22, 1986.

87. Direct Testimony of Dale G. Bridenbaugh and Richard B. Hubbard on behalf of The Public Parties Committee, Public Utility Commission of Texas, regarding the Evaluation of Costs of River Bend Nuclear Generating Station, in the matter of application of Gulf States Utilities for authority to change rates, Docket Nos. 7195 and 6755, February 23, 1987.

88. Direct Testimony of Dale G. Bridenbaugh on behalf of Maryland People's Counsel, in the matter of the Application of the Baltimore Gas and Electric Company to Adjust Its Electric Fuel Rate Charges, Pursuant to Section 54F of Article 78 of the Annotated Code of Maryland, Case No. 8520-D, April 29, 1987.

89. Direct Testimony of Dale G. Bridenbaugh on behalf of Florida Office of Public Counsel, in regard to Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor (Florida Power Corporation - Crystal River 3), Docket No. 860001-EI-B, June 12, 1987.

90. Direct Testimony of Dale G. Bridenbaugh on behalf of the Residential Ratepayer Consortium, before the Michigan Public Service Commission, in the matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery Costs and Revenues for Calendar Year 1986, Palisades Nuclear Power Plant, Case No. U-8286-R, July 13, 1987.

91. Direct Testimony of Dale G. Bridenbaugh on behalf of the City of El Paso, before the Public Utility Board, in the matter of the Application of the El Paso Electric Company for a Rate Increase in the City of El Paso, Evaluation of Costs of Palo Verde Units 1 and 2, July 15, 1987.

92. Direct Testimony of Dale G. Bridenbaugh on behalf of the City of El Paso, before the Public Utility Commission of Texas, in the matter of the Application of the El Paso Electric Company for Authority to *Increase Electric Rates, Evaluation of Operational and Decommissioning Costs of Palo* Verde *Units* 1 *and* 2, Docket No. 7460, July 29, 1987.

93. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor on behalf of Massachusetts Attorney General, before the Federal Energy Regulatory Commission, regarding Canal Electric Company Prudence Related to Seabrook Unit 2 Construction Expenditures, Docket No. ER86-704-001, July 31, 1987.

94. Direct Testimony of Dale G. Bridenbaugh on behalf of Maryland People's Counsel, before the Public Service Commission of Maryland, in the matter of the Application of Delmarva Power & Light Company for Electric Fuel Rate Adjustment, Pursuant to Section 54F of Article 78, of the Annotated Code of Maryland, Case No 8521, Phase II, August 10, 1987, PROPRIETARY.

95. Direct Testimony of Dale G. Bridenbaugh and Gregory C. Minor before the Pennsylvania Public Utility Commission, Regarding The Extended Outages at Beaver Valley Unit 1, Docket No. I-79070318, OCA Statement No. 2, August 31, 1987.

96. Direct Testimony of Dale G. Bridenbaugh on behalf of Maryland People's Counsel, Case No. 8520-C, in the Matter of the Application of the Baltimore Gas & Electric Company to Adjust its Electric Fuel Rate Charges, Pursuant to Section 54F of Article 78 of the Annotated Code of Maryland, before the Public Service Commission of Maryland, October 20, 1987.

97. Direct Testimony of Dale G. Bridenbaugh on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, regarding Evaluation of Perry Plant Power Ascension Program, Docket Nos. R-870651 and R-870732, OCA Statement No. 7, October 1987.

98. Surrebuttal Testimony of Dale G. Bridenbaugh before the Pennsylvania Public Utility Commission, regarding Beaver Valley Unit 1, Docket No. I-79070318, OCA Statement No. 2A, October 30, 1987.

99. Surrebuttal Testimony of Dale G. Bridenbaugh before the Pennsylvania Public Utility Commission, on behalf of the Pennsylvania Office of Consumer Advocate, regarding Evaluation of Perry Plant Power Ascension Program, Docket Nos. R-870651 and R-870732, December 1987.

100. Surrebuttal Testimony of Dale G. Bridenbaugh before the Public Service Commission of Maryland, on behalf of Maryland People's Counsel, in the matter of the Application of the Baltimore Gas and Electric Company to Adjust Its Electric Fuel Rate Charges, Pursuant to Section 54F of Article 78 of The Annotated Code of Maryland, Case No. 8520-C, December 17, 1987.

101. Direct Testimony of Dale G. Bridenbaugh before the Michigan Public Service Commission on behalf of the Michigan Attorney General Concerning Evaluation of the Investment - Midland Nuclear Power Station, in the Matter of the Application of Consumers Power Company for Authority to Increase Its Rates for the Sale of Electricity, Case No. U-7830 (Midland), Step 3B, December 29, 1987.

102. Direct Testimony of Dale G. Bridenbaugh before the Minnesota Public Utilities Commission on behalf of the Minnesota Department of Public Service Concerning Northern States Power's Decommissioning Cost Estimates for the Monticello and the Prairie Island Nuclear Power Station, in the Matter of the Application of Northern States Power Company for Authority To Increase Its Rates for Electric Services in Minnesota, Docket No. E-OOZ/GR-87-670, February 19, 1988.

103. Direct Testimony and Exhibits of Dale G. Bridenbaugh on behalf of Residential Ratepayers Consortium before the Michigan Public Service Commission, State of Michigan, in the Matter of the application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery (PSCR) Costs and Revenues for Calendar Year 1987, Case No. U-8545R (1987 PSCR Reconciliation), August 17, 1988.

104. GE Reed Report Safety Issue Reviews, Issues 9, 11, 13, and 23, prepared by MHB Technical Associates for The Ohio State University Nuclear Engineering Program Expert Review Panel, Public Utility Commission of Ohio, October 1988.

105. *Direct Testimony and Exhibits of Dale G. Bridenbaugh, Gregory C. Minor and Steven C. Sholly on* Behalf of Massachusetts Department of the Attorney General, Re: Pilgrim Nuclear Power Station, Investigation of Pilgrim Outage, DPU 88-28, November 30, 1988, PROTECTED INFORMATION.

106. *Direct Testimony of Dale G. Bridenbaugh, on behalf of Pennsylvania Office of Consumer Advocate,* Re: Salem Generating Station Unit No. 1 Seventh Refueling Outage, Docket Nos. I-880082, M-880189, M-880189C001, and M-880189C002, December 1988.

107. Supplemental Testimony of Dale G. Bridenbaugh, Gregory C. Minor and Steven C. Sholly on Behalf of Massachusetts Department of the Attorney General, Re: Pilgrim Nuclear Power Station, Investigation of Pilgrim Outage, DPU 88-28, January 20, 1989, Exhibit AG-2.

108. Surrebuttal Testimony of Dale G. Bridenbaugh, on behalf of Pennsylvania Office of Consumer Advocate, Re: Salem Generating Station Unit No. 1 Seventh Refueling Outage, Docket Nos. I-880082, M-880189, M-880189C001, and M-880189C002, February 1989.

109. Oral Testimony of Dale G. Bridenbaugh, U. S. District Court, Brooklyn, New York, February 10, 1989, re: County of Suffolk vs. LILCO et. al., Case 87 CIV. 646 (JBW).

110. Surrebuttal Testimony of Dale G. Bridenbaugh, Gregory C. Minor and Steven C. Sholly on Behalf of Massachusetts Department of the Attorney General, Re: Pilgrim Nuclear Power Station, Investigation of Pilgrim Outage, DPU 88-28, February 13, 1989, Exhibit AG-74.

111. Surrebuttal Testimony of Dale G. Bridenbaugh, Gregory C. Minor and Steven C. Sholly on Behalf of Massachusetts Department of the Attorney General, Re: Pilgrim Nuclear Power Station, Investigation of Pilgrim Outage, DPU 88-28, February 17, 1989, Exhibit AG-93.

112. Direct Testimony and Exhibits of Dale G. Bridenbaugh on Behalf of The Residential Ratepayer Consortium, before the Michigan Public Service Commission, in the Matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery of Costs and Revenues for the Calendar Years 1986 and 1987, Case No. U-8286-R and Case No. U-8545-R Reopened (Capacity Factor), July 7, 1989.

113. Direct Testimony of Dale G. Bridenbaugh on Behalf of Maryland People's Counsel, before the Public Service Commission of Maryland, in the Matter of the Investigation by the Commission of the Justness and Reasonableness of the Rates of Baltimore Gas and Electric Company, Case No. 8190, and in the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Rates, Case No. 8208, July 19, 1989. PROTECTED INFORMATION.

114. Surrebuttal Testimony of Dale G. Bridenbaugh on Behalf of Maryland People's Counsel, before the Public Service Commission of Maryland, in the Matter of the Investigation by the Commission of the Justness and Reasonableness of the Rates of Baltimore Gas and Electric Company, Case No. 8190, and in the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Rates, Case No. 8208, August 23, 1989.

115. Direct Testimony and Exhibits of Dale G. Bridenbaugh on Behalf of The Residential Ratepayer Consortium, before the Michigan Public Service Commission, in the Matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery Costs and Revenues for the Calendar Year 1988, Case No. U-8866-R, August 25, 1989.

116. Direct Testimony of Dale G. Bridenbaugh on Behalf of Pennsylvania Office of Consumer Advocate, Concerning the Prudence of the Limerick Generating Station Unit 2 Construction, Philadelphia Electric Company v. Pennsylvania Public Utility Commission, Docket No. R-891364, October 1989.

117. Direct Testimony of Dale G. Bridenbaugh on Behalf of the New Jersey Department of the Public Advocate, Division of Rate Counsel, before the Board of Public Utilities, in the Matter of Electric Utility Nuclear Performance Standards, BPU Docket No. EX89080719, November 2, 1989.

118. Surrebuttal Testimony of Dale G. Bridenbaugh on Behalf of Pennsylvania Office of Consumer Advocate, Concerning the Prudence of the Limerick Generating Station Unit 2 Construction, Philadelphia Electric Company v. Pennsylvania Public Utility Commission, Docket No. R-891364, December 1989.

119. Oral Testimony of Dale G. Bridenbaugh, U.S. District Court, Phoenix, Arizona, February 12-13, 1990, re: Washington Public Power Supply vs. General Electric Company, et al, Case No. C-85-98 AAM.

120. Direct Testimony of Dale G. Bridenbaugh on behalf of The City of El Paso in the matter of the Application of El Paso Electric Company for a Rate Increase, before the Public Utility Regulation Board of The City of El Paso, February 16, 1990.

121. Direct Testimony of Dale G. Bridenbaugh on behalf of The City of El Paso in the Application of El Paso *Electric Company to establish performance standards for the Palo Verde Nuclear Generating Station; for* approval of deferred accounting treatment of certain costs related to Palo Verde Unit 3; and for authority to change rates. Docket Nos. 8892, 9069, and 9165, before the Public Utility Commission of Texas, February 21, 1990.

122. Direct Testimony of Dale G. Bridenbaugh and Peter M. Strauss on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the Board of Public Utilities, in the matter of Jersey Central Power & Light Co. for Approval of an Amendment of its Tariff to Provide for an Increase in Rates and Charges for Electric Service and for an Increase in the Levelized Energy Adjustment Clause, BPU Docket No. ER89110912J, June 29, 1990.

123. Supplemental Testimony of Dale G. Bridenbaugh and Peter M. Strauss on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the State of New Jersey Board of Public Utilities, in the matter of JCP&L Company for Approval of an Amendment of its Tariff to Provide for an Increase in Rates and Charges for Electric Service and for an Increase in the Levelized Energy Adjustment Clause, BPU Docket No. ER89110912J, August 16, 1990.

124. Direct Testimony of Dale G. Bridenbaugh on behalf of The Cook County State's Attorney's Office and The City of Chicago, before the State of Illinois, Illinois Commerce Commission, in the matter of Commonwealth Edison Company Proposed General Increase in Electric Rates, Docket No. 90-0169, August 24, 1990.

125. Direct Testimony and Exhibits of Dale G. Bridenbaugh on behalf of The Residential Ratepayer Consortium, before the Michigan Public Service Commission, in the matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery Costs and Revenues for the Calendar Year 1989, Case No. U-9172-R, October 1, 1990.

126. Surrebuttal Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the State of New Jersey Board of Public Utilities, in the matter of JCP&L Company for Approval of an Amendment of its Tariff to Provide for an Increase in Rates and Charges for Electric Service and for an Increase in the Levelized Energy Adjustment Clause, BPU Docket No. ER89110912J, October 17, 1990.

127. Direct Testimony of Dale G. Bridenbaugh and Peter M. Strauss on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the State of New Jersey Board of Public Utilities, in the Matter of the Petition for Atlantic Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, BPU Docket No. ER90091090J, April 30, 1991.

128. Direct Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the State of New Jersey Board of Regulatory Commissioners, Office of Administrative Law, in the Matter of the Petition of Public Service Electric and Gas Company for Approval of the 1990 TLG Decommissioning Studies and the Nuclear Decommissioning Costs Set Forth Therein, OAL Docket No. 088689-91 N, BRC Docket No. EE91081429, March 5, 1992.

129. Direct Testimony of Dale G. Bridenbaugh on behalf of New Jersey Department of the Public Advocate, Division of Rate Counsel, Before the State of New Jersey Board of Regulatory Commissioners, Office of Administrative Law, in the Matter of the Petition of Public Service Electric and Gas Company for an Increase in Base Rate for Electric and Gas Service, OAL Docket No. ER91111698J, BRC Docket No. PUC 11058-91, June 11, 1992.

130. Direct Testimony of Dale G. Bridenbaugh on behalf of Residential Ratepayer Consortium, Before the *Michigan Public Service Commission, in the Matter of the Application of Consumers Power Company for* a Reconciliation of Power Supply Cost Recovery Costs and Revenues for the Calendar Year 1991, Case No. U-9732R (1991 PSCR Reconciliation), June 19, 1992.

131. Direct Testimony of Dale G. Bridenbaugh on behalf of Pennsylvania Office of Consumer Advocate, Before the Pennsylvania Public Utility Commission, in the Matter of the Pennsylvania Public Utility Commission v. Metropolitan Edison Company, Docket No. R-922314, GPU Industrial Intervenors v. Metropolitan Edison Company, Docket M-920312C006, August 20, 1992.

132. Surrebuttal Testimony and Exhibits of Dale G. Bridenbaugh on Behalf of Pennsylvania Office of Consumer Advocate, Before the Pennsylvania Public Utility Commission, in the Matter of the *Pennsylvania Public Utility Commission v. Metropolitan Edison Company*, Docket No. R-922314, *GPU* Industrial Intervenors v. Metropolitan Edison Company, Docket M-920312C006, September 25, 1992.

133. Direct Testimony of Dale G. Bridenbaugh on behalf of the Texas Office of Public Utility Counsel, Before the Public Utility Commission of Texas, in the Matter of the Application of Texas Utilities Electric Company For Authority To Change Rates, Comanche Peak Nuclear Issues (Revenue Requirements Phase), Docket No. 11735, April 19, 1993. CONTAINS CONFIDENTIAL INFORMATION.

134. Direct Testimony of Dale G. Bridenbaugh on behalf of Residential Ratepayer Consortium, Before the Michigan Public Service Commission, in the Matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery Costs and Revenues for the Calendar Year 1992, Case No. U-9960R (1992 PSCR Reconciliation), July 16, 1993.

135. Expert Report: Evaluation of GSU's Representations To Cajun Relative to the Effect of the General Electric Nuclear Steam Supply System, Including the Power Generation Control Complex and the Mark III Containment Loads, on the Cost and Construction Schedule for the River Bend Nuclear Stations. In the United States District Court for the Middle District of Louisiana, Cajun Electric Power Cooperative, Inc. vs. Gulf States Utilities Company, Civil Action Number 89-474-B, December 1993.

136. Direct Testimony of Dale G. Bridenbaugh on behalf of Residential Ratepayer Consortium, Before the Michigan Public Service Commission, in the Matter of the Application of Consumers Power Company for a Reconciliation of Power Supply Cost Recovery Costs and Revenues for the Calendar Year 1993, Case No. U-10155R (1993 PSCR Reconciliation), July 6, 1994.

137. Direct Testimony of Dale G. Bridenbaugh on behalf of The New Jersey Division of Ratepayer Advocate, Before the State of New Jersey Board of Public Utilities, Office of Administrative Law, in the Matter of the Motion of Public Service Electric & Gas Company to Increase the Level of the Levelized Energy Adjustment Clause, Docket No. BPU No. ER94070293, OAL No. PUC 7328-94, November 10, 1994.

EXHIBIT DGB-2

ARTICLE FROM *POWER* MAGAZINE

"WORLD'S FIRST NUCLEAR-TO-COAL CONVERSION A SUCCESS"

APRIL 1992

World's first nuclear-to-coal conversion a success

Faced with the prospect of huge financial losses on a 97%-complete nuclear station, owners rapidly converted the facility to coal firing. Modularization proved to be the key to economical reconstruction

Zimmer generating station, the word's first nuclear-to-coal conversion, is located on the Ohio River 25 miles southeast of Cincinnati (Fig 1). The plant began commercial operation in March 1991—two months ahead of schedule and 20% under budget. The redesigned plant comprises a single, 1300-MW, base-load unit that is equipped with state-of-the-art pollution-control and waste-handling systems. Operating experience to date is reportedly outstanding (see box on next page). For its resourceful conversion and subsequent operating success, Zimmer receives POWER's 1992 Powerplant Award.

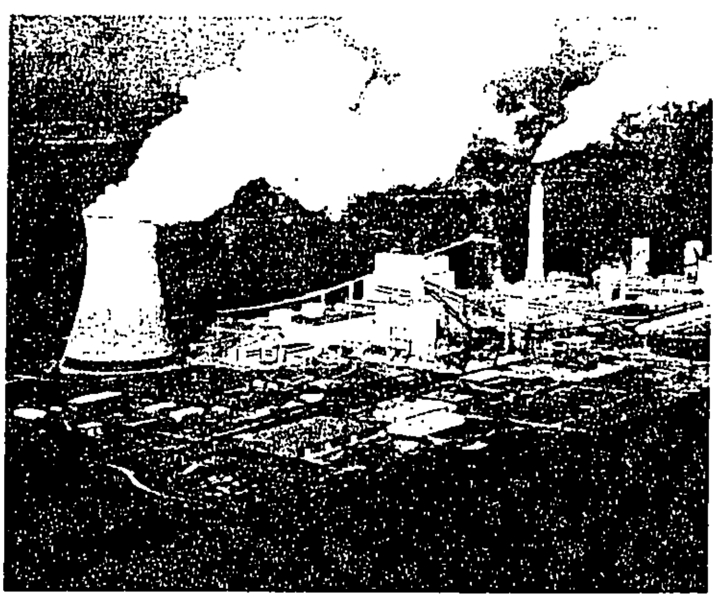
History

In 1982, the Nuclear Regulatory Commission (NRC) forced a halt to construction on the 97%-complete Zimmer—then a planned 800-MW nuclear facility—ostensibly for safety-related reasons. The three owners—Cincinnati Gas & Electric Co (CG&E), Columbus Southern Power Co (a subsidiary of American Electric Power Co), and Dayton Power & Light Co—were forced to take a hard look at the project after a study by Bechtel Power Corp revealed that even if construction were completed, there would be no assurances that the NRC would grant an operating license.

With projected completion costs of \$1.8-billion over the \$1.7-billion already spent, the owners announced an agreement in early 1984 to use their best efforts to convert Zimmer to a coal-fired unit. Ownership percentages were realigned and all nuclear-construction expenditures were stopped immediately.

Additional studies indicated that a supercritical unit with reheat provided the lowest cost per kilowatt, lowest heat rate, maximum use of existing equipment, a 60% increase in capacity, and high potential reliability. In 1984, the owners announced their decision to convert Zimmer to a 1300-MW, coal-fired installation—the largest coal-fired unit built worldwide.

There are only nine 1300-MW units operating today, seven of which were engineered and designed by American Electric Power Service Corp (AEPSC) for the American Electric Power System. The six earlier units provided a proven base-line design for the conversion project.



1. **Zimmer station,** once intended for nuclear service, was converted to coal firing when the NRC halted construction of the original plant

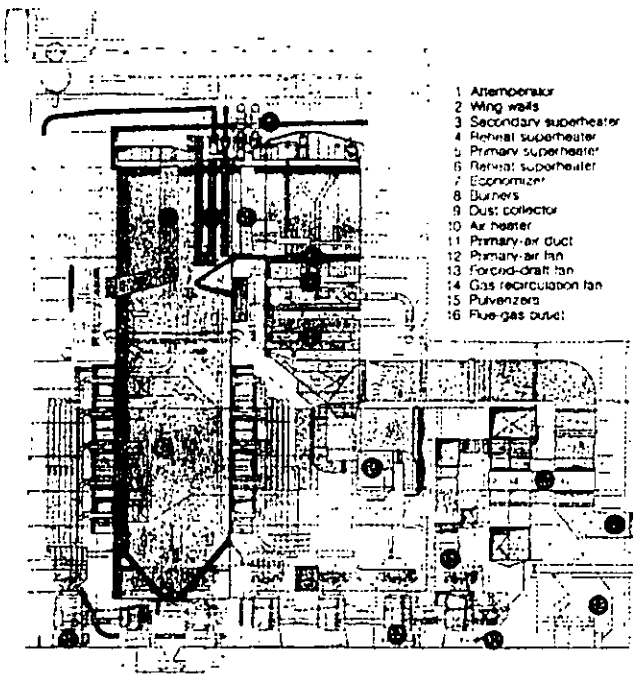
Conversion

As with any project of this size and scope, construction and logistics were complex. Faced with a site of only 305 acres—30% of the area of the smallest 1300-MW site previously used—without rail access and only limited truck access, AEPSC had to re-examine its project-management and construction techniques.

Cost restraints. The Public Utilities Commission (PUC) of Ohio stipulated that \$861-million of the owners' nuclear investment must be written off. Further, a cap of \$3.6-billion was set as the maximum amount the three owners could request for inclusion in the rate base when the converted station was completed. These provisos further emphasized the need for innovative project-management techniques. Additionally, new permits were required to meet federal, state, and local regulations for a coal-fired powerplant. In fact, the start of construction was delayed three months by a late permit from one agency.

AEPSC's experience on its previous six 1300-MW units proved invaluable in streamlining the construction process with extensive up-front planning—including integration of scheduling, expenditures, and manufacturing and labor resources. Project management also relied on modularization as a tool to achieve project objectives.

Modularization. Extensive reliance on modularization provided Zimmer with the necessary streamlined critical path. Prima-



First nine months indicate operating success

Since entering service in March 1991, the Zimmer station has run with virtually no significant problems, according to plant personnel. To eliminate a minor turbine/generator vibration, a short outage is expected to be taken during April 1992. Otherwise, no planned outages are scheduled until next October. Similar to AEP's other 1300-MW units, Zimmer is following an 18-month maintenance outage schedule.

The following operating information sums up Zimmer's first nine months of operation:

- Equivalent availability 91.4%
- Capacity factor 86%
- Net generation .... 7.43-million MWh
- Net output factor—or percentage of the facility's 8148 on-line hours the plant was run at full-load 93.6%
- Equivalent forced-outage rate 5.6%
- Average heat rate .... 9440 Btu/kWH
- SO_2-removal efficiency 91.84%

2. Steam generator produces 9.8-million lb/hr of steam for use by the h-p turbine

ry benefits include minimized lay-down area requirements, shortened construction schedule by one year, reduced project costs, and levelized on-site manpower requirements.

It is important to distinguish between true modularization and pre-assembly: while benefits accrue from both, modularization's potential saving is more significant. More to the point, pre-assembly refers to partially assembling some of the components of a system or piece of equipment near the construction site before moving them into place. Such pre-assembly does not necessarily require engineering and design support and the decision to pre-assemble usually occurs during the construction phase of a project.

Modularization, on the other hand begins in the earliest stages of project planning because vendors often must modularize a component in their shop for shipment. Because the modules are usually large, access roads, transport equipment, and installation apertures all must be fixed early in construction.

Super crane. To carry out this plan, AEP leased a 1200-ton-capacity crane which could lift oversize components off transport barges and directly into position. More than 200 major components were handled this way, including:

- The electrostatic precipitator, which was assembled at a shipyard in Mobile, Ala. and transported in 30 modules—weighing up to 500 tons—via ocean-going barges up the Mississippi and Ohio Rivers.
- Two 375,000-lb/hr auxiliary boilers weighing 450 tons each.
- Fourteen fully assembled pulverizers weighing 150 tons each.
- Six scrubber modules, which were shipped in two pieces per module, both weighing close to 100 tons.
- Three 200-ton regenerative air heaters.
- High- and intermediate-pressure turbines, weighing 130 and 150 tons, respectively, fully assembled in Europe and shipped by barge.

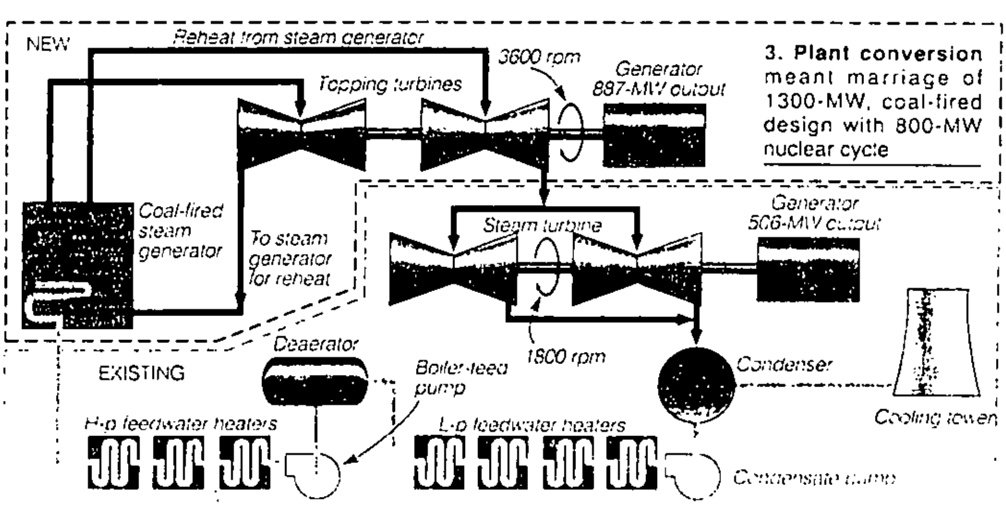
Project description

The coal-fired, supercritical steam generator used at Zimmer is designed to burn 535 tons/hr of pulverized, high-sulfur bituminous coal (Fig 2). It produces 9.8-million lb/hr of 3690-psig/1000F steam for use by the high-pressure turbine. The boiler is designed to reduce NO_x formation during combustion to below 0.6 lb/million Btu of heat input.

With the exception of the addition of induced-draft fans, a wet scrubber, and a fifth burner level, the boiler train is essentially identical to other AEP 1300-MW units. The use of induced-draft fans changes the unit from pressurized to balanced-draft operation. A single boiler-feed-pump turbine drives a single feed pump—a feature unique to AEP's 1300-MW units.

Turbine/generators. The cross-compound turbine/generator system incorporates the low-pressure turbine/generator set from the nuclear cycle with a new high- and intermediate-pressure (h-p/i-p) turbine/generator. The coupled h-p and i-p turbines drive a generator rated 975 MVA to produce 900 MW. Because the project called for maximum use of the existing equipment, the original condenser, feedwater heaters, cooling tower, and most other balance-of-plant equipment were incorporated into the new design (Fig 3). The h-p turbine/generator from the nuclear cycle was removed to maximize performance and minimize maintenance of the new arrangement.

Zimmer's steam path is virtually identical to that of AEP's other 1300-MW plants. Steam flows from the boiler through four combined main stop and control valves to the double-flow high-pres-



3. Plant conversion meant marriage of 1300-MW, coal-fired design with 800-MW nuclear cycle sure turbine. After a reheat cycle, it passes through four combined intercept and stop valves to the double-flow i-p turbine. Steam exits the i-p turbine and travels to the two double-flow low-pressure turbines via a 240-ft-long, 84-in.-diameter crossover pipe. The low-pressure turbines drive the original generator to produce 500 MW.

At startup, the crossover pipe is relatively cold, creating some condensation within the pipe for initial steam flows. To prevent water flow into the l-p turbines, a moisture collector/drain system is installed just upstream of where the pipe splits to carry flow to the two turbines.

A new shaft-driven oil pump, speed pickups, and a shaft run-out (eccentricity) monitor were relocated to the front of the first l-p turbine. Other modifications to the l-p unit include removal of inlet-row rotating and stationary blades from both turbines and removal of intercept control and stop valves.

The h-p turbine/generator is designed to reduce maintenance requirements. For example, generator stator windings are water-cooled. In addition, the rotor body is machined from a single-piece forging and is supported on pedestal bearings. Lastly, the rotor can be removed without disassembly of the stator's one-piece end brackets.

Turbine controls. Because the distance to the h-p/i-p shaft line is too great for a fast response by a hydraulic system, the l-p-turbine mechanical overspeed trips were replaced with electronic ones. The turning gear for the l-p shaft line was replaced with a new design that permits two-speed operation—4 rpm for normal mode and 24 rpm for synchronization of the generator fields prior to operation.

The turbine control system is equipped with a mechanical speed-governor backup. To avoid a turbine trip caused by overspeed, an acceleration limiter was added to the speed governor. The h-p shaft line is equipped with two mechanical overspeed trips. At overspeed, the bolts strike the latches in the tripping devices, which opens a direct drain from corresponding emergency oil circuits. Mechanical overspeed trips are sequentially adjusted at 110 and 112%, respectively, and can be tested during normal operation with oil injection.

The electronic overspeed trips on the h-p shaft line are set for 105%; a solenoid trips the turbine. The same setpoint is used on the l-p shaft-line trips.

Emissions control. A cold-side electrostatic precipitator (ESP) manufactured by Flakt Inc (now ABB Flakt), Knoxville, Tenn, removes particulates from the flue-gas stream to ensure compliance with federal and state regualtions. Removal efficiency is 99.8% and emissions are limited to 0.025 lb/million Btu of heat input.

To comply with SO_2-emissions regulations, Zimmer is equipped with a magnesium-enhanced, lime-based, flue-gas desulfurization (FGD) system that was designed to remove a minimum of 91% of the SO_2 produced in the combustion process (Fig 4). However, the system has consistently removed over 94% of the SO_2 generated during its first year of operation. This accomplishment was recognized in late 1991 when the plant won EPA's "Award for Excellence in SO_2 Control." Regulations require that SO_2 emissions be limited to 0.548 lb/million Btu of heat input. The special FGD sorbent is supplied by Dravo Lime Co, Pittsburgh, Pa.

The FGD system is anchored by six scrubber modules arranged in a semi-circle around the stack. System design is based on an inlet gas temperature of 345F, an inlet SO_2 loading of 2.5 to 8.6 lb/million Btu, a coal sulfur content of 1.5 to 4.5%, and a stoichiometric ratio of 1.03. Inlet flow rate is 4.9-million acfm.

The magnesium-enhanced lime process provides several advantages because of its high reactivity. For example: fewer mass-transfer devices—sprays, trays, and packing—are required in the absorber vessel and overall vessel size is relatively small. Because fewer internals are needed, the pressure drop through the absorber vessel—and parasitic power consumption—is reduced. High reactivity also contributes to low liquid-to-gas ratios, which lower energy consumption by lime-slurry pumps. Additionally, high alkalinity produces a highly buffered solution less affected by load swings and upsets.

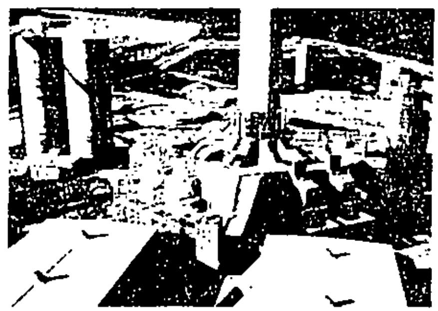
Operation of the FGD system produces a mud-like sludge byproduct which is combined with flyash from the ESP and additional lime to form a solid granular substance suitable for Zimmer's dedicated landfill.

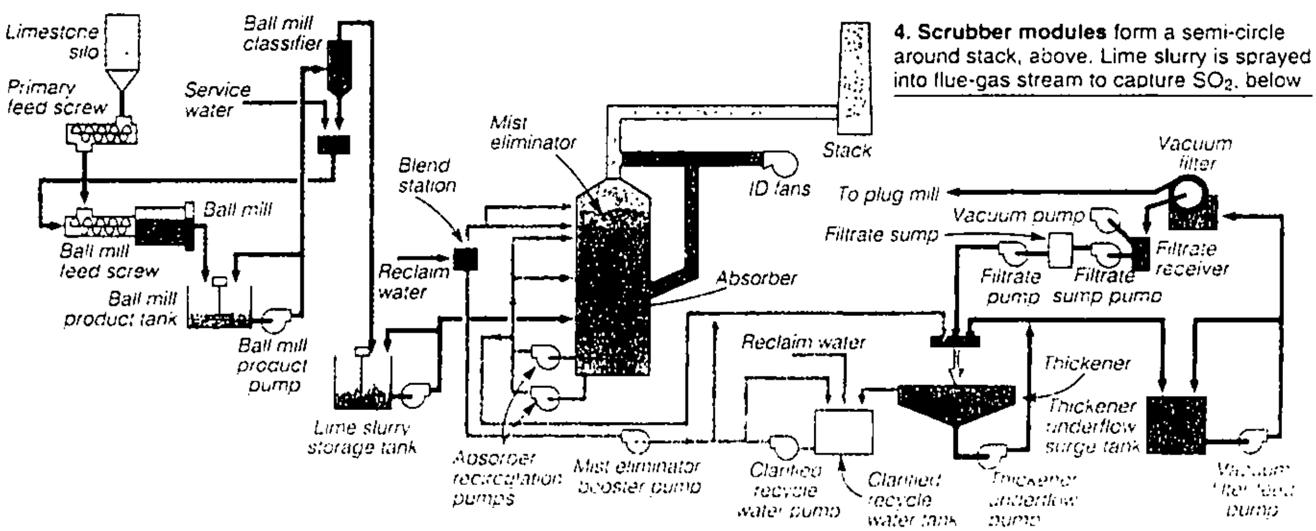
There are four main steps to the FGD process at Zimmer, including:

- **Lime preparation and feed.** Here, the magnesium-enhanced lime is converted to a slaked lime slurry by a ball mill. Each 15,000-ton lime storage silo has a dedicated ball-mill slaking system fed by screw feeders. Slaking water and oversize slurry particles are recirculated through the mill. Because water never mixes with the dry lime until entering the mill, premature mixing and plugging is virtually eliminated.

Note that a separate inerts-removal system is unnecessary, because they are ground with the lime in the slaking process and need not be removed until dewatering occurs. Two slurry tanks provide at least seven hours of storage. Two 100%-capacity feed pumps for each tank provide slurry to either feed loop.

- **Six stainless steel absorber vessels** are the heart of the FGD system. Flue gas is discharged from a single induced-draft fan to each module. Flue-gas flow through





4. Scrubber modules form a semi-circle around stack, above. Lime slurry is sprayed into flue-gas stream to capture SO_2, below the modules is countercurrent to the slurry spray. One absorber is maintained in reserve at all times.

A perforated absorber tray extends across the absorber vessel horizontally and is flooded with recirculated slurry by the upper spray header. The tray ensures even distribution of the gas flow and provides an area of intimate contact between flue gas and slurry. From the tray, flue gas filters down through absorber sprays. Mist eliminators remove any water remaining before the flue gas is released to the chimney.

■ **Primary and secondary dewatering.** Spent slurry from the absorbers is pumped to two of three 50%-capacity thickeners, sized to produce a 25%-solids concentration in the underflow. A second dewatering by vacuum filter increases the solids concentration to 40%.

■ **Waste stabilization and disposal.** Once dewatered, the filter cake is fixed and stabilized with the addition of flyash and lime in a pug mill. This operates as a batch process for a maximum of 16 hours daily. Once stabilized, the material is conveyed to a stackout pad. From there, it is hauled to the landfill. **Steven Collins**

Major equipment suppliers

Turbine/generator and auxiliaries

Turbine/generator, high-pressure/intermediate-pressure, 1 ....ABB Asea Brown Boveri (Switzerland)
900 MW, 3690 psig/1000F/1000F, 3600 rpm, tandem compound, single reheat, double flow, extraction for eight stages of feedwater heating; 3 phase, 60 Hz, 975 MVA (0.95 power factor)

Turbine/generator, low-pressure, 1 ....Westinghouse Electric Corp
500 MW, 121 psig/585F, 1800 rpm, tandem compound, four flow; 3 phase, 60 Hz, 780 MVA (0.935 power factor)

Main condenser, 1 ..Cochrane Environmental Systems Div, Crane Co
(See our ad, p 60)
Single pass, divided waterbox, dual pressure, single shell, 550,000 ft^2 surface area, 1-in.-diam (OD) 90/10 Cu/Ni tubes

Main-condenser exhausters, 2 ....Nash Engineering Co; Schutte & Koerting Div, Ketema Inc
Rotary water-ring type vacuum pumps for hogging operations, steam-jet air ejectors for holding operations

Auxiliary condenser, 1 ....Cochrane Environmental Systems Div, Crane Co
(See our ad, p 60)
Single pass, divided waterbox, single pressure, single shell, 105,700 ft^2 surface area, 0.75-in-diam (OD) 90/10 Cu/Ni tubes

Auxiliary condenser exhausters, 2 ....Nash Engineering Co
Two-stage rotary water-ring type vacuum pumps handle both hogging and holding operations

Circulating-water pumps, 3...................Foster Wheeler Energy Corp
(See our ad, p 12)
Each one-third size, vertical, single stage, volute type, 150,000 gpm at 78-ft total head; 3500-hp, 294-rpm motor drive

Cooling tower, 1 ....Hamon Cooling Towers
(See our ad, p 167)
Natural-draft counterflow tower, 445,000 gpm of 94F cold water produced at 76F ambient (wet bulb), 53% relative humidity with 24.5 deg F range

Steam-generation equipment

Steam generator, 1 ....Babcock & Wilcox Co
9.775-million-lb/hr main steam at 3845 psig/1010F, single reheat, balanced draft, 7656-million-lb/hr reheat flow, 1000F reheater-outlet temperature with 670-psig/562F inlet steam, furnace 111 ft wide (overall) × 110 ft deep (furnace, convection pass) × 216 ft tall (throat to top of penthouse), designed to limit NO_x formation to 0.6 lb/million Btu heat input

Burners, 98 ....Babcock & Wilcox Co
Five elevations of dual-register burners arranged for front- and rear-wall firing, 49 burners per wall, one igniter per burner, No.-2-oil igniter fuel

Pulverizers, 14 ....Babcock & Wilcox Co
Each mill feeds seven burners and has independently operated hot- and cold-air dampers to maintain a constant primary-air flow and to regulate pulverizer exit temperature

Gravimetric feeders, 14 (one per mill) ....Stock Equipment Co

Primary-air fans, 3..Howden Sirocco Inc

Forced-draft fans, 3...Howden Sirocco Inc

Regenerative air heaters, 3.............................ABB Air Preheater Inc
(See our ad, p 195)

Induced-draft fans, 6 (one per absorber module)................................ ....Howden Sirocco Inc

Sootblowers, 153...............................Diamond Power Specialty Co

EXHIBIT DGB-3

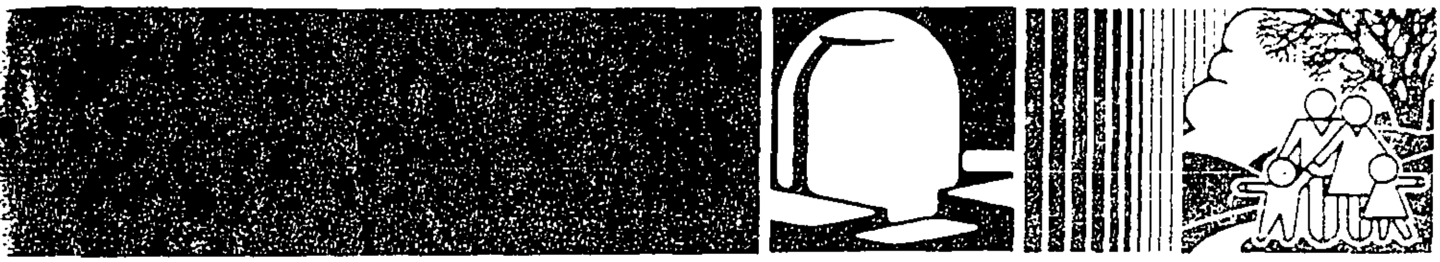
FIGURE 1 - TURBINE BUILDING, PUMP HOUSE,

WATER INTAKE AND DISCHARGE SYSTEMS,

TRAINING CENTER, AND AUXILIARY BUILDING

DOE/SSDP-0081

SHIPPINGPORT STATION DECOMMISSIONING PROJECT



FINAL PROJECT REPORT

SHIPPINGPORT STATION DECOMMISSIONING PROJECT

December 22, 1989

Prepared for the:

U.S. Department of Energy
Richland Operations Office
Shippingport Station Decommissioning Project Office

Prepared by:

Westinghouse Hanford Company
Shippingport Station Decommissioning Project Office
Post Office Box 323
Shippingport, Pennsylvania 15077
Under Contract DE-AC06-87RL10930

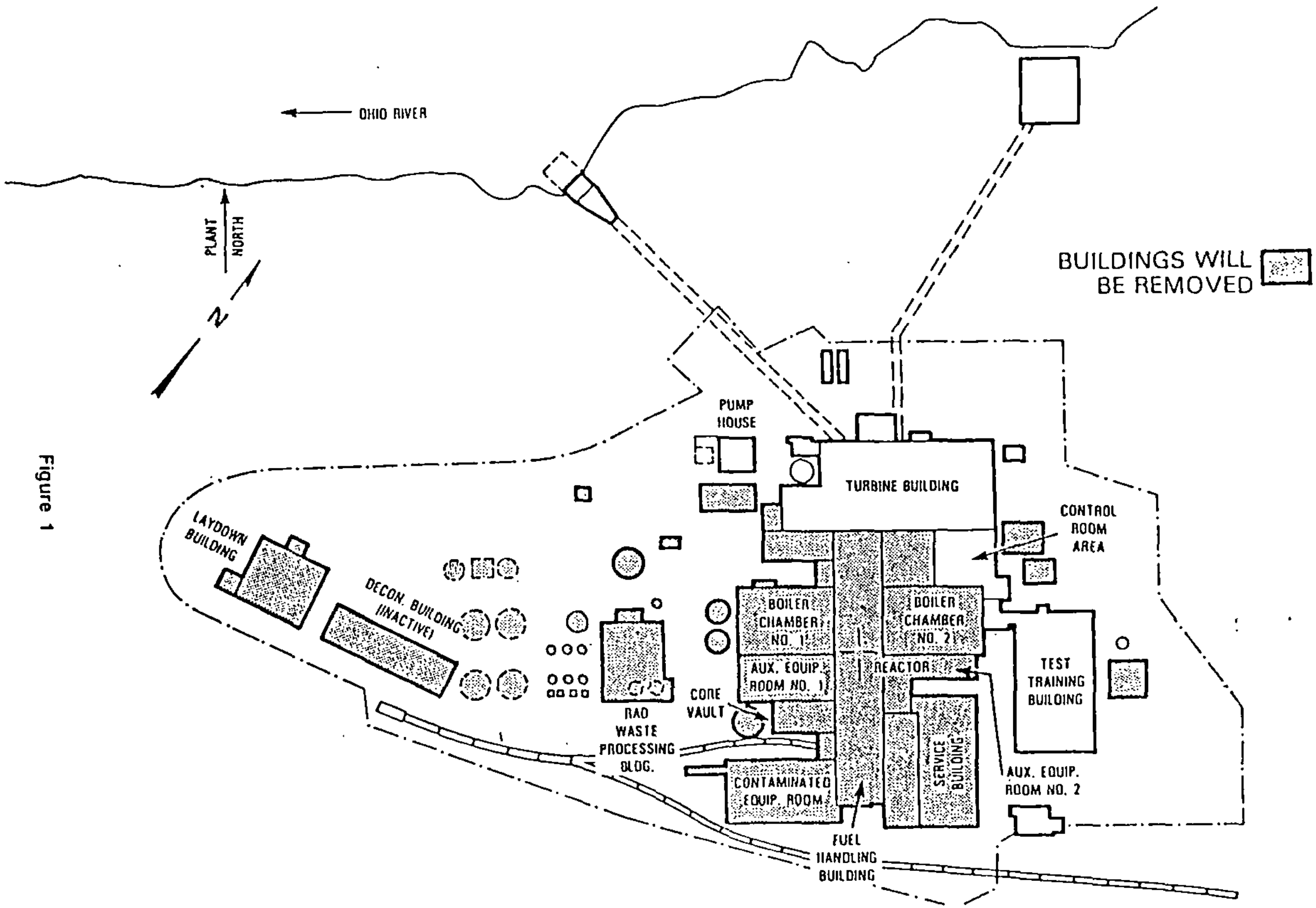


Figure 1

SSDP Site Plot Plan Showing Structures to be Removed

EXHIBIT DGB-4

<u>RESPONSE TO OCA-VIII-11</u>

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set VIII
Dated February 23, 1995
Docket No. R-00943271

Q.11. Referring to Response 24 of OCA Interrogatory Set II, please describe in detail Pennsylvania Power & Light's (PP&L's) basis and related decision making documentation that provide the basis for the conclusion that the "remaining structures would be impractical for use in another industrial capacity." Please explain whether this is an opinion of PP&L management, or whether there has been any detailed evaluation of potential future uses of the power plant site. If there have been any studies or documents regarding the potential future use of the site, please provide.

A.11. PP&L's basis for the conclusion that the remaining non-radioactively contaminated structures would be impractical for use in another capacity is based upon a TLG recommendation and PP&L's judgment. Many of these structures will be significantly damaged by the explosive demolition required to remove the radioactive portions of the structures. Additionally, the ages of these structures following decontamination will be at least 50 years from the construction dates. In PP&L's judgment, there is a major uncertainty of any remaining salvage value at that age. Consequently, PP&L plans to demolish these structures and restore the site to a natural condition.

PP&L has not performed a detailed evaluation of future uses of the power plant site.

EXHIBIT DGB-5

<u>RESPONSE TO OCA-II-10</u>

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

EXHIBIT DGB-6

AFFIDAVIT OF JAMES CLEARY

COMMISSION OF MICHIGAN LOW-LEVEL

RADIOACTIVE WASTE AUTHORITY

Exhibit 5
Page 1 of 2

STATE OF MICHIGAN

MICHIGAN LOW-LEVEL RADIOACTIVE WASTE AUTHORITY
106 West Allegan, 574 Hollister Building
P.O. Box 30026, Lansing, Michigan 48909
517/335-0430

JAMES F. CLEARY, Commissioner

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

AFFIDAVIT OF JAMES F. CLEARY

James F. Cleary, being sworn, says:

1. I am the Commissioner of the Michigan Low-Level Radioactive Waste Authority.

2. Currently the Authority has not developed the mandated fee structure required under Section 19 of Public Act 204 of 1987, so we are unable to officially determine what the actual disposal costs will be at a low-level radioactive waste isolation facility if one is sited, built, and operated within Michigan. However, Authority staff has undertaken to develop an estimate of what disposal costs are likely to be at such a facility. These estimates are based on Michigan remaining in the Midwest Interstate Low-Level Radioactive Waste Compact and on assuming that the volume of waste to be disposed of annually during the life of the facility will be in excess of 96,000 cubic feet per year.

3. Costs contained in the spreadsheet which developed these disposal costs are our staff's best estimate of pre-operation costs (including site characterization costs, bonding costs and Authority operations), facility design and construction costs, operation costs, post-closure costs, and all fees and funds required under existing Michigan law,

specifically Public Act 204 of 1987. The disposal fees estimated are also based solely upon the volume of waste isolated and do not address the radioactivity, half-life, the differential costs to dispose of the various classes of waste, or the current allocation of all Class C waste disposal fees to the Clean Michigan Fund, all of which are required under Public Act 204. Thus, should the law remain in its current form, the disposal costs for Class A and B waste would be significantly higher than that estimated by Authority staff.

4. Estimated costs to dispose of 96,676 feet of low-level radioactive waste are approximately $450 per cubic foot, $380 for 115,000 cubic feet (the current Compact estimated annual volume) and $270 to dispose of 165,000 cubic feet of waste (the 1988 Compact estimated annual volume). All cost estimates are in 1988-1989 dollars.

James F. Cleary

James F. Cleary, Commissioner
Michigan Low-Level Radioactive
Waste Authority

Subscribed and sworn to before me
this eighteenth day of May, 1990.

Cheryl L. Brand

Cheryl L. Brand, Notary Public

Ingham County, Michigan
My Commission Expires November 22, 1993.

CHERYL L. BRAND
Notary Public, Ingham County, MI
My Commission Expires Nov. 22, 1993

OPERATING BUDGET - Commence Operations 10/1/93 (all figures in thousands of dollars)

DRAFT

		FY 2003	FY 2004	FY 2005	FY 2006	FY 2006	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	TOTAL TO DATE
Comments	RADIOACTIVE WASTE AUTHORITY														
	Full Time Equated Positions	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	
	Authority Staff & Expenses	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	21434.7
by 10-1/88 up to $1Million	Research Institute	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	44403.1
FY 88 Reduced phase in	AG Interdepartment Grant	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	4099.8
1sm. half first year bid	DAG - Contract Audit Fee	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	298.8
Negotiated Reduction	MDPH Interdepartment Grant	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	35617.3
	Contribution to Compact	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	6420.6
	RWCC														18.2
Sec 13 - by 6/1/88	Review Board														55.0
Sec 14 - by 6/1/88	Local Monitoring Committees	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	1121.5
Section 8	Siting Citizens Advisory Committee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0
	Site Selection Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	358.8
7/1/88 - 7/1/89	Site Characterization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12408.6
Design 7/1/88 - 10/1/88	Facility Design														2500.0
	Facility Construction														20500.0
	Facility Operations	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	205000.0
10/1/88 - 3/1/90	Site Purchase (1540 Acres)														2000.0
	Community Relations Contract														1249.5
	License Preparation														5000.0
	Revenue System Development														600.0
0%	Compact Payback	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Negotiate between 11/1/88 2/1/8	Host Site Community Costs	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
Negotiate between 11/1/88 2/1/8	Host Site Incentive Package	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
Section 13714	Site Closure & Stabilization Bond														10000.0
Section 13714	Dec & Inst Control Bond														30000.0
Section 13715	Liability Bond														10000.0
In addition to above incentives	Unrestricted State Contribution	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
In addition to above incentives	Unrestricted Host Site Contribution	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	16800.0
	Municipal/County Externalities														1800.0
See footnote #1	Debt Service	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	On-Call Technical Assistance														2325.0
Section 13715	Liability Insurance & Legal Defense	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	15750.0
	TOTAL COSTS	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Section 19(2)	SPECIAL FUNDS														
	Remedial Action														10000.0
Last source after closure & liability	Long-Term Liability														10000.0
Bonds	Long-Term Care														12000.0
	Tax Contingency	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	2100.0
	TOTAL SPECIAL FUNDS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	34100.0
	TOTAL COSTS TO OPERATE FACILITY	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SPECIAL SURCHARGES (20%)														
$400K or 35% of fee	Host Site Community	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	2555.8	51116.2
$400K or 20% of fee	Bordering Municipalities	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	29200.2
$300K or 15% of fee	County of Host Site	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	21806.9
$400K or 15% of fee	Environmental Response Fund	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	21806.9
$700K or 15% of fee	Clean Michigan Fund	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	1095.3	21906.8
	TOTAL SPECIAL SURCHARGES	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	7302.3	146045.2
BONDING INFORMATION															
103000															
PRINCIPLE															
8.25%	REVENUES														
INTEREST RATE															
20	Appropriated From:														
TIME PERIOD	LLRWF														57713.5
108940	PSC Fees														10238.3
ACTUAL BOND REVENUE GENERATED	Bond Revenue														100940.0
	Waste Disposal Facility Spec Fund	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	876271.3
	TOTAL REVENUES	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	43813.6	1045163.1
	TOTAL EXPENSES	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SURPLUS/(DEFICIT)	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	

OPERATING BUDGET Commence Operations 10/1/95

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Comments		FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003
Comments	RADIOACTIVE WASTE AUTHORITY																
	Full Time Equated Positions	18.0	18.3	20.0	22.0	22.0	22.0	22.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
	Authority Staff & Expenses	818.3	1360.3	1570.3	1796.4	1796.4	1796.4	1796.4	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
by 10/1/88 up to $1Million	Research Institute	80.0	183.5	107.6	111.9	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
FY 88 Reduced phase in	AG Interdepartment Grant	75.0	148.4	156.3	160.5	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4
Low bid first year bid	OAG - Contract Audit Fee	12.0	15.6	15.5	16.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Negotiated Reduction	MDPH Interdepartment Grant	100.0	727.0	804.2	1510.1	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0
	Contribution to Compact	120.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
	RACC	19.7	0.0	0.0	0.0	0.0	0.0	0.0									
Sec 13 by 8/1/88	Review Board	0.0	15.0	20.0	20.0	0.0	0.0	0.0									
Sec 16 by 8/1/88	Local Monitoring Committees	0.0	300.0	161.5	150.0	100.0	100.0	100.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Section 8	Siting Criteria Advisory Committee	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Site Selection Contract	275.0	83.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7/1/88 - 7/1/89	Site Characterization	0.0	2400.6	8000.0	2000.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Design 7/1/88 - 10/1/88	Facility Design	0.0	0.0	1600.0	1000.0												
	Facility Construction						3000.0	10000.0	5500.0								
	Facility Operations								5000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10030.0
10/1/89 3/1/90	Site Purchase (1040 Acres)	0.0	0.0	500.0	1500.0												
	Community Relations Campaign	55.0	784.6	200.0	200.0												
	License Preparation	0.0	0.0	0.0	0.0		4000.0										
	Revenue System Development			600.0													
0%	Compact Payback									#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Negotiation between 11/1/88 2/1/89	Host Site Community Costs								500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
Negotiation between 11/1/88 2/1/89	Host Site Incentive Package								550.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
Section 13714	Site Closure & Stabilization Bond								10000.0								
Section 13716	Ops & Inst Control Bond								20000.0								
Section 13715	Liability Bond								10000.0								
In addition to above incentives	Unrestricted State Contribution								500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
In addition to above incentives	Unrestricted Host Site Contribution								800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
	Municipal/County Expenditures								400.0	400.0	400.0	400.0					
See footnote 01	Debt Service									#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	On Call Technical Assistance	25.0	600.0	300.0	300.0	300.0	300.0	300.0	300.0								
Section 13715	Liability Insurance & Legal Defense								750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
	TOTAL COSTS	1685.3	6456.1	14033.6	8755.2	5703.0	15703.0	15703.0	68887.4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Section 18(2)	SPECIAL FUNDS																
	Remedial Action								[illegible]								
Less amount after closure & Liability Bonds	Long Term Liability								[illegible]								
	Long Term Care								12000.0								
Section 18(2)d	Tax Contingency								100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	TOTAL SPECIAL FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	TOTAL COSTS TO OPERATE FACILITY	1685.3	6456.1	14033.6	8755.2	5703.0	15703.0	15703.0	100987.4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SPECIAL SURCHARGES (gen.)																
$400K at 35% of fee	Host Site Community					0.35				2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9
$400K at 20% of fee	Bordering Municipalities					0.20				1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5
$300K at 15% of fee	County of Host Site					0.15				1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4
$400K at 15% of fee	Environmental Response Fund					0.15				1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4
$700K at 15% of fee	Clean Michigan Fund					0.15				1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4
						0.15											
	TOTAL SPECIAL SURCHARGES						0.0	0.0	0.0	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6
BONDING INFORMATION																	
102000																	
PRINCIPAL																	
6.25%	REVENUES																
INTEREST RATE																	
20	Appropriated From																
TIME PERIOD	Licenses	3000.0	3500.0	12630.2	4963.2	3637.4	13983.0	13983.1									
100944	PSC Fees	924.0	1127.7	1403.3	1720.0	1720.0	1720.0	1720.0									
ACTUAL BOND REVENUE GENERATED	Bond Revenue								100940.0								
	Waste Disposal Fees (in Spec. Funds)								0.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0
	TOTAL REVENUES	3924.0	4734.2	14033.6	8684.1	5358.2	15703.0	15703.0	100940.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0
	TOTAL EXPENSES	1685.3	6456.1	14033.6	8755.2	5703.0	15703.0	15703.0	100887.4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SURPLUS (DEFICIT)	2238.7	-1721.9	-0.1	-151.1	-345.8	0.0	0.1	272.8	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	ACCUMULATED SURPLUS (DEFICIT)	2238.7	516.8	516.7	365.6	0.0	0.0	0.1	272.8	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

All figures shown in thousands of dollars

OPERATING BUDGET Commence Operations 10/1/95

		FY 2004	FY 2005	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	TOTAL TO DATE
Commence	RADIOACTIVE WASTE AUTHORITY													
	Full Time Equated Positions	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	
	Authority Staff & Expenses	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	21434.7
by 10/1/84 up to $1 billion	Research Institute	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	48403.1
FY 88 Reduced phase in	AG - Interdepartment Grant	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	148.4	4099.8
Low ball first year bid	OAG - Contract Audit Fee	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	256.8
Programmed Reduction	MDPH Interdepartment Grant	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	1349.0	35617.3
	Contribution to Compact	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	8420.5
	RWCC													19.2
Sec. 13 - by 9/1/88	Review Board													85.0
Sec 14 - by 9/1/88	Local Monitoring Committees	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	1121.6
Section 8	Siting Criteria Advisory Committee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0
	Site Selection Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	354.8
7/1/88 - 7/1/89	Site Characterization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12408.6
Design 7/1/88 - 10/1/90	Facility Design													2500.0
	Facility Construction													20500.0
	Facility Operations	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	10000.0	205000.0
10/1/92 - 2/1/93	Site Purchase (1000 Acres)													2000.0
	Community Relations Contract													1248.1
	License Preparation													5000.0
	Revenue System Development													600.0
0%	Compact Payback	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Negotiate between 11/1/90 2/1/9	Host Site Community Grant	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
Negotiate between 11/1/90 2/1/9	Host Site Improvement Package	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
Section 13714	Site Closure & Stabilization Bond													10000.0
Section 13714	Ops & Inst. Control Bond													30000.0
Section 13715	Liability Bond													10000.0
In addition to above incentives	Unrestricted State Contribution	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	10500.0
In addition to above incentives	Unrestricted Host Site Contribution	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	16800.0
	Municipal/County Exemptions													1600.0
See bottom #1	Debt Service	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	On-Call Technical Assistance													2325.0
Section 13716	Liability Insurance & Legal Defense	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	15750.0
	TOTAL COSTS	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Section 19(1)	SPECIAL FUNDS													
	Remedial Action													10000.0
Last source after closure & Liability	Long Term Liability													10000.0
Bonds	Long Term Care													12000.0
Section 19(2)(d)	Tax Contingency	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	2100.0
	TOTAL SPECIAL FUNDS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	34100.0
	TOTAL COSTS TO OPERATE FACILITY	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SPECIAL SURCHARGES (20%)													
$400K @ 35% of fee	Host Site Community	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	2555.9	61117.9
$400K @ 20% of fee	Bordering Municipalities	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	1460.5	20210.2
$300K @ 15% of fee	County of Host Site	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	21907.7
$400K @ 15% of fee	Environmental Response Fund	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	21907.7
$300K @ 15% of fee	Clean Michigan Fund	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	1095.4	21907.7
	TOTAL SPECIAL SURCHARGES	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	7302.6	146050.0
BONDING INFORMATION														
103000														
PRINCIPLE													#REF!	
8.25%	REVENUES													
INTEREST:														
20	Appropriated From													
TIME PERIOD	LLRWF													57713.5
100940	PSC Fees													10238.3
ACTUAL BOND REVENUE GENERATED 0	Bond Revenue													100940.0
	Waste Disposal Facility Spec. Fund	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	876300.0
	TOTAL REVENUES	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	43815.0	1045101.0
	TOTAL EXPENSES	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SURPLUS/(DEFICIT)	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	
	ACCUMULATED SURPLUS/(DEFICIT)	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

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All figures shown in thousands of dollars

OPERATING BUDGET - Commence Operations 10/1/95 (all figures in thousands of dollars)

		FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002
Comments	RADIOACTIVE WASTE AUTHORITY															
	Full Time Equated Positions	16 0	18 3	20 0	22 0	22 0	22 0	22 0	13 0	13 0	13 0	13 0	13 0	13 0	13 0	13 0
	Authority Staff & Expenses	816 3	1360 3	1570 3	1786 4	1796 4	1796 4	1796 4	500 0	500 0	500 0	500 0	500 0	500 0	500 0	500 0
by 10/1/88 up to $1Million	Research Institute	80 0	103 5	107 6	111 9	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0	2000 0
FY 88 Reduced phase in	AG - Interdepartment Grant	75 0	148 4	154 3	160 5	148 4	148 4	148 4	148 4	148 4	148 4	148 4	148 4	148 4	148 4	148 4
Low bid first year bid	OAG - Contract Audit Fee	12 0	15 0	15 6	16 7	10 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0
Negotiated Reduction	MDPH Interdepartment Grant	100 0	727 0	904 2	1510 1	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0	1349 0
	Contribution to Compact	120 0	0 0	0 0	0 0	0 0	0 0	0 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0
	RACC	10 2	0 0	0 0	0 0	0 0	0 0	0 0								
Sec 13 - by 8/1/88	Review Board	0 0	15 0	20 0	30 0	0 0	0 0	0 0								
Sec 14 - by 6/1/88	Local Monitoring Committees	0 0	300 0	161 5	150 0	100 0	100 0	100 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0	10 0
Section 8	Siting Criteria Advisory Commit	5 0	0 0	0 0	0 0	0 0	0 0	0 0		0 0	0 0	0 0	0 0	0 0	0 0	0 0
	Site Selection Contract	275 0	83 8	0 0	0 0	0 0	0 0	0 0		0 0	0 0	0 0	0 0	0 0	0 0	0 0
7/1/88 - 7/1/88	Site Characterization	0 0	3408 8	8000 0	2000 0	0 0	0 0	0 0		0 0	0 0	0 0	0 0	0 0	0 0	0 0
Design 7/1/88 - 10/1/89	Facility Design	9 9	0 0	1500 0	1000 0											
	Facility Construction						5000 0	10000 0	5500 0							
	Facility Operations								5000 0	10000 0	10000 0	10000 0	10000 0	10000 0	10000 0	10000 0
10/1/89 - 3/1/90	Site Purchase (1540 Acres)	0 0	0 0	500 0	1500 0											
	Community Relations Contract	65 0	784 8	200 0	200 0											
	License Preparation	0 0	0 0	0 0	0 0		5000 0									
	Revenue System Development			600 0												
8%	Compact Payback									#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Negotiate between 11/1/88 2/1/8	Host Site Community Costs								600 0	600 0	500 0	500 0	500 0	500 0	500 0	500 0
Negotiate between 11/1/88 2/1/8	Host Site Incentive Package								500 0	600 0	500 0	500 0	500 0	500 0	500 0	500 0
Section 13714	Site Closure & Stabilization Bond								10000 0							
Section 13714	Off-Site & Inst Control Bond								30000 0							
Section 13715	Liability Bond								10000 0							
In addition to above incentives	Unrestricted State Contribution								500 0	500 0	500 0	500 0	500 0	500 0	500 0	500 0
In addition to above incentives	Unrestricted Host Site Contribution								800 0	800 0	800 0	800 0	800 0	800 0	800 0	800 0
	Municipal/County Externalities								400 0	400 0	400 0	400 0				
See footnote #1	Debt Service									#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	On Call Technical Assistance	25 0	100 0	300 0	300 0	300 0	300 0	300 0	300 0							
Section 13715	Liability Insurance & Legal Defense								750 0	750 0	750 0	750 0	750 0	750 0	750 0	750 0
	TOTAL COSTS	1585 3	6456 1	14033 8	8785 2	5703 8	15703 8	15703 8	84587 4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Section 19(2)	SPECIAL FUNDS															
	Remedial Action								10000 0							
Last ... after closure & Liability	Long-Term Liability								10000 0							
Bonus	Long-Term Care								12000 0							
	Tax Contingency								100 0	100 0	100 0	100 0	100 0	100 0	100 0	100 0
	TOTAL SPECIAL FUNDS	0 0	0 0	0 0	0 0	0 0	0 0	0 0	32100 0	100 0	100 0	100 0	100 0	100 0	100 0	100 0
	TOTAL COSTS TO OPERATE FACILITY	1585 3	6456 1	14033 6	8785 2	5703 8	15703 8	15703 8	100667 4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SPECIAL SURCHARGES (20%)															
$400K or 35% of fee	Host Site Community					0 35				2555 8	2555 8	2555 8	2555 8	2555 8	2555 8	2555 8
$400K or 20% of fee	Bordering Municipalities					0 20				1460 5	1460 5	1460 5	1460 5	1460 5	1460 5	1460 5
$300K or 15% of fee	County of Host Site					0 15				1095 3	1095 3	1095 3	1095 3	1095 3	1095 3	1095 3
$400K or 15% of fee	Environmental Response Fund					0 15				1095 3	1095 3	1095 3	1095 3	1095 3	1095 3	1095 3
$200K or 15% of fee	Clean Michigan Fund					0 15				1095 3	1095 3	1095 3	1095 3	1095 3	1095 3	1095 3
							84474 0									
	TOTAL SPECIAL SURCHARGES						0 0	0 0	0 0	7302 3	7302 3	7302 3	7302 3	7302 3	7302 3	7302 3
BONDING INFORMATION						TIPPING FEE										
183000																
PRINCIPLE																
8 25%	REVENUES															
INTEREST RATE																
20	Appropriated From															
TIME PERIOD	LLRWMF	3000 0	3586 5	12630 2	8883 3	3637 4	13983 0	13983 1								
100950	PSC Fees	824 0	1127 7	1403 3	1720 6	1720 8	1720 8	1720 8								
ACTUAL BOND REVENUE GENERATED	Bond Revenue								100840 0							
	Waste Disposal Fees inc. Spec. Funds								0 0	43813 6	43813 6	43813 6	43813 6	43813 6	43813 6	43813 6
	TOTAL REVENUES	3824 0	4724 2	14033 5	8604 1	5356 2	15703 8	15703 9	100840 0	43813 6	43813 6	43813 6	43813 6	43813 6	43813 6	43813 6
	TOTAL EXPENSES	1585 3	6456 1	14033 6	8785 2	5703 8	15703 8	15703 8	100667 4	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	SURPLUS/(DEFICIT)	2238 7	-1731 8	-0 1	-181 1	-345 6	0 0	0 1	172 6	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

DRAFT

COST COMPARISON

DRAFT

	Annual Volume	Tipping Fee Includes Surcharge	Annual Incentive Payments	Cash Surplus
Michigan Alone	27,126	$1,300.00	$5,877,300	#REF!
	85,000	$465.90	$6,600,250	#REF!
[redacted]			$7,302,261	#REF!
			$7,302,500	#REF!
	165,000	$265.60	$7,304,000	#REF!
'roposed Compac	423,231	$107.50	$7,582,889	#REF!
	567,893	$91.20	$10,358,368	#REF!

PERCENTAGE CHANGE TABLE

VOLUME		TIPPNG FEE		INCENTIVES	
27,126	-71.94%	$1,300.00	186.85%	$5,877,300	-23.05%
85,000	-12.08%	$465.90	2.80%	$6,600,250	-13.59%
96,676	0.00%	$453.20	0.00%	$7,302,261	-4.40%
115,000	18.95%	$381.00	-15.93%	$7,302,500	-4.40%
165,000	70.67%	$265.60	-41.39%	$7,304,000	-4.38%
423,231	337.78%	$107.50	-76.28%	$7,582,889	-0.73%
567,893	487.42%	$91.20	-79.88%	$10,358,368	35.61%

EXHIBIT DGB-7

GAO/RCED-90-171, P. 5

GAO

Report to the Honorable Vic Fazio, House of Representatives

NUCLEAR R & D

Usefulness of Information From Shippingport Decommissioning for Rancho Seco

POOR ORIGINAL

remain on the site. EPA has been developing such standards for several years and expects to make them final no sooner than 1993. NRC will then incorporate EPA's standards into its regulations.

In the absence of EPA standards, DOE required at Shippingport that public exposure from residual contamination should not exceed 100 millirem per person per year.[7] DOE's report on the project indicates that public exposures will not exceed 2 millirem annually. In the absence of EPA's standards, NRC has been suggesting that utilities decontaminate to a level that would limit public exposures to 10 millirem a year—10 times less than DOE required at Shippingport.[8]

Decommissioning Costs

DOE spent $91.3 million to decommission Shippingport. Although little actual data exist on the costs to decommission a large commercial plant, most estimates are in the hundreds of millions of dollars. Some of the difference in costs between Shippingport and commercial plants can be attributed to labor rates, costs for removing the pressure vessel, and waste disposal costs. DOE documents show that it saved about $7 million in decommissioning costs by removing the pressure vessel intact. Utilities may not be able to use this option because of site-specific problems to remove and transport the vessel in one piece. Also, the much higher radioactivity in the pressure vessel may preclude its disposal in a commercial site.

Furthermore, DOE sent all decommissioning waste from Shippingport to its Hanford facility for disposal. Utilities will eventually have to dispose of their waste in commercial sites—at a much higher cost. For example, in 1986, low-level waste disposal costs at Hanford were $3.95 per cubic foot; by 1989 the cost had increased to about $27.60 per cubic foot.[9] Also, after January 1993, low-level waste disposal costs could range from $50 to $590 or more per cubic foot as a result of costly new facilities—possibly as many as 16—that may be built by states or interstate compacts to dispose of low-level waste. Therefore, significant differences exist between DOE's waste disposal costs for Shippingport and those that could be experienced by nuclear utilities.

[7]Rem (Roentgen Equivalent Man) is a measurement used to quantify the effects of radiation on man. A millirem is a thousandth of a rem.

[8]Currently, 11 nuclear plants are shut down; NRC has approved decommissioning plans for 5 of the plants.

[9]The $27.60 does not include packaging, transportation, labor, materials, taxes, or the cubic-foot surcharges allowed by the Low-Level Radioactive Waste Policy Act, as amended.

EXHIBIT DGB-8

RESPONSE TO OCA-II-4

T. S. LaGuardia

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

Q.4. Please provide a Table that includes information on all nuclear plant decommissioning cost estimates prepared by TLG since January 1, 1989. This Table should include:

a. Total decommissioning cost estimate;
b. Total cost for LLRW burial;
c. Total contingency;
d. Craft labor contingency;
e. Assumed cost of storage of high level waste;
f. Total cost of non-radioactive decommissioning;
g. Unit cost of LLRW burial ($/cu. ft.).

A.4. The requested information is provided as Attachment 1.

DECOMMISSIONING SUMMARY

(since 1989)

	UTILITY	PLANTS	PLANT DESIGN	FILED OPTION	BASE YEAR [4]	TOTAL DECOMMISSIONING COST ESTIMATE ($Millions)	TOTAL CONTINGENCY (%)	CRAFT LABOR CONTINGENCY (%)	[1] STORAGE OF HIGH-LEVEL WASTE ($Millions)	[2] CLEAN DEMOLITION COST ($Millions)	UNIT COST of LLRW DISPOSAL ($/cubic foot)	LLRW BURIAL VOLUME (cubic yards)	[3] LLRW BURIAL COST ($Millions)
1	ALABAMA POWER	FARLEY 1	PWR	DECON	1989	102.318	25	n/a	n/a	33.892	36.87	10,001	17.00
		FARLEY 2	PWR	DECON	1989	217.544	25	n/a	n/a	39.201	36.87	8,446	18.80
		FARLEY 1	PWR	DECON	1993	275.78	18.41	23.15	n/a	38.794	228.00	4,630	48.60
		FARLEY 2	PWR	DECON	1993	302.008	19.85	22.94	n/a	50.430	228.00	4,676	53.70
2	ARIZONA PUBLIC SERVICE	PALO VERDE 1	PWR	DECON	1989	249.450	25	n/a	n/a	56.134	29.80	16,304	18.80
		PALO VERDE 2	PWR	DECON	1989	247.317	25	n/a	n/a	55.093	29.80	16,236	17.80
		PALO VERDE 3	PWR	DECON	1989	262.990	25	n/a	n/a	79.560	29.80	15,200	17.10
		PALO VERDE 1	PWR	DECON	1992	442.149	25	n/a	n/a	97.475	373.00	16,278	162.94
		PALO VERDE 2	PWR	DECON	1992	435.047	25	n/a	n/a	57.676	373.00	16,212	156.06
		PALO VERDE 3	PWR	DECON	1992	456.483	25	n/a	n/a	82.544	373.00	16,181	157.03
3	CAROLINA POWER & LIGHT	BRUNSWICK 1	BWR	DECON	1989	216.367	25	n/a	n/a	47.200	36.87	21,662	36.70
		BRUNSWICK 2	BWR	DECON	1989	199.90	25	n/a	n/a	29.493	36.87	20,078	34.70
4	MAINE YANKEE	MAINE YANKEE	PWR	DECON	1993	316.623	15.92	20.22	n/a	41.313	400.00	6,543	79.00
5	CONNECTICUT YANKEE	CONNECTICUT YANKEE	PWR	DECON	1992	309.113	16.23	n/a	n/a	31.898	398.00	3,712	57.60
6	CONSUMERS POWER	BIG ROCK POINT	BWR	DECON	1989	104.326	25	n/a	11.54 *	24.402	300.00	4,821	36.60
		PALISADES	PWR	DECON	1989	315.971	25	n/a	6.14 *	48.170	300.00	7,631	88.70
7	DUKE POWER	OCONEE 1	PWR	DECON	1990	153.326	25	n/a	-	22.798	36.87	8,832	21.10
		OCONEE 2	PWR	DECON	1990	148.845	25	n/a	-	21.174	36.87	10,663	22.40
		OCONEE 3	PWR	DECON	1990	247.538	25	n/a	56.15 *	38.492	36.87	11,679	22.90
		CATAWBA 1	PWR	DECON	1990	156.490	25	n/a	-	26.852	36.87	12,808	16.00
		CATAWBA 2	PWR	DECON	1990	240.615	25	n/a	82.63	40.334	36.87	13,384	20.80
		McGUIRE 1	PWR	DECON	1990	149.909	25	n/a	-	25.723	36.87	11,402	20.80
		McGUIRE 2	PWR	DECON	1990	209.602	25	n/a	44.87	40.335	36.87	11,622	21.80
8	EL PASO ELECTRIC	PALO VERDE 1	PWR	DECON	1993	357.542	16.49	24.30	n/a	51.517	279.00	7,308	78.80
		PALO VERDE 2	PWR	DECON	1993	340.542	16.06	24.38	n/a	55.095	279.00	7,229	78.30
		PALO VERDE 3	PWR	DECON	1993	700.872	14.14	23.55	270.14	287.295	279.00	7,244	78.10
9	ENTERGY OPERATIONS	WATERFORD 3	PWR	DECON	1993	320.120	17.31	22.87	n/a	30.091	281.60	7,318	79.80
		GRAND GULF	BWR	DECON	1993	406.508	21.39	24.75	n/a	44.481	145.60	12,280	96.30
10	FLORIDA POWER CORP.	CRYSTAL RIVER 3	PWR	DECON	1991	293.136	18.95	n/a	29.86	53.813	62.50	7,116	34.10
				DECON	1994	391.034	17	22.07	44.83	63.548	230.00	4,048	47.10
11	FLORIDA POWER & LIGHT	ST. LUCIE 1	PWR	DECON	1994	297.579	17.85	24.9	n/a	34.024	241.60	6,601	56.44
		ST. LUCIE 2	PWR	DECON	1994	307.272	17.61	22.72	n/a	38.260	241.60	4,936	55.27
		TURKEY POINT 3	PWR	DECON	1994	248.748	17.85	23.72	n/a	18.764	241.60	4,108	49.45
		TURKEY POINT 4	PWR	DECON	1994	299.208	17.67	22.23	n/a	36.069	241.60	4,611	53.22
12	GEORGIA POWER COMPANY	VOGTLE 1	PWR	DECON	1990	263.987	25	n/a	n/a	77.781	80.00	8,770	31.20
		VOGTLE 2	PWR	DECON	1990	329.226	25	n/a	n/a	82.664	80.00	11,367	39.20
		HATCH 1	BWR	DECON	1990	235.621	25	n/a	n/a	32.403	80.00	16,103	45.00
		HATCH 2	BWR	DECON	1990	311.283	25	n/a	n/a	54.721	80.00	18,636	52.80
13	GULF STATES UTILITIES CO.	RIVER BEND	BWR	DECON	1990	382.548	23.06	n/a	n/a	63.158	250.00	17,857	130.54
14	HOUSTON LIGHTING & POWER	SOUTH TEXAS PROJECT 1	PWR	DECON	1989	217.19	25	n/a	n/a	45.505	36.87	17,772	34.90
		SOUTH TEXAS PROJECT 2	PWR	DECON	1989	245.971	25	n/a	n/a	77.298	36.87	19,077	38.60
		SOUTH TEXAS PROJECT 1	PWR	DECON	1994	406.479	13.98	22.61	41.6	47.552	290.00	10,888	112.00
		SOUTH TEXAS PROJECT 2	PWR	DECON	1994	556.754	14.23	21.19	105.62	83.631	290.00	11,474	117.00
15	IOWA ELECTRIC L&P	DUANE ARNOLD	BWR	DECON	1989	295.721	25	n/a	n/a	51.305	350.00	16,082	31.23
				DECON	1993	318.115	16.02	n/a	n/a	46.242	350.00	6,496	78.80
16	NORTH ATLANTIC ENERGY CO.	SEABROOK 1	PWR	DECON	1991	323.624	20.63	n/a	n/a	71.778	138.00	8,766	49.60
				DECON	1993	345.150			n/a		180.00	9,047	
				DECON	1994	360.930	17.14	22.32	n/a	75.015	233.00	8,894	68.50
17	NORTHEAST UTILITIES	MILLSTONE 1	BWR	DECON	1992	350.864	15.9[illegible]	n/a	n/a	45.934	398.00	8,161	113.50
		MILLSTONE 2	PWR	DECON	1992	281.796	16.18	n/a	n/a	34.162	398.00	5,335	62.30
		MILLSTONE 3	PWR	DECON	1992	383.175	16.06	n/a	n/a	56.158	398.00	7,028	85.40
18	NORTHERN STATES POWER	MONTICELLO	BWR	DECON	1990	334.083	25	n/a	56.657	n/a	89.60	13,561	27.50
		MONTICELLO	BWR	DECON	1993	298.518	17.71	32.09	n/a		300.00	4,880	52.38
		PRARIE ISLAND 1	PWR	DECON	1990	140.41	25	n/a	n/a	n/a	89.60	5,522	13.10
		PRARIE ISLAND 2	PWR	DECON	1990	212.306	25	n/a	49.725	n/a	89.60	6,088	14.20
		PRARIE ISLAND 1	PWR	DECON	1993	207.178	16.97	20.31	n/a	17	300.00	2,690	38.50
		PRARIE ISLAND 2	PWR	DECON	1993	245.127	17.01	25.43	n/a	35	300.00	3,227	41.30
19	NPPD	COOPER	BWR	DECON	1988	316.626	25	n/a	n/a	43.182	114.00	21,357	70.80
				DECON	1993	424.336	15.57	24.48	70.84	37.132	350.00	6,818	107.80
20	PACIFIC GAS & ELECTRIC	HUMBOLT BAY 3	BWR	SAFSTOR	1991	78.214	20.42	n/a	n/a	10.132	179.00	2,828	18.00
				SAFSTOR	1994	102.523	21.88	25.56	n/a	7.531	350.00	2,038	25.20
		DIABLO CANYON 1	PWR	DECON	1991	327.625	19.82	n/a	n/a	71.272	179.00	13,273	67.60
		DIABLO CANYON 2	PWR	DECON	1991	385.181	19.22	n/a	n/a	145.345	179.00	12,880	65.50
		DIABLO CANYON 1	PWR	DECON	1994	340.786	16.56	22.12	33.57	50.701	350.00	5,306	73.50
		DIABLO CANYON 2	PWR	DECON	1994	497.88	16.13	19.3	33.46	204.034	350.00	5,423	74.80
21	PENNSYLVANIA POWER & LIGHT	SUSQUEHANNA 1	BWR	DECON	1993	350.524	16.37	24.52	n/a	45.662	279.00	8,454	78.21
		SUSQUEHANNA 2	BWR	DECON	1993	453.735	17.75	22.43	n/a	81.723	279.00	9,626	80.69
22	PUBLIC SERVICE ELECTRIC & GAS	PEACH BOTTOM 2	BWR	DECON	1990	254.005	25	n/a	5.98	n/a	81.03	17,863	50.50
		PEACH BOTTOM 3	BWR	DECON	1990	314.805	25	n/a	16.55	n/a	81.03	20,382	56.70

2/9/95

DECOMMISSIONING SUMMARY

(since 1989)

	UTILITY	PLANTS	PLANT DESIGN	FILED OPTION	BASE YEAR (#)	TOTAL DECOMMISSIONING COST ESTIMATE ($Millions)	TOTAL CONTINGENCY (%)	CRAFT LABOR CONTINGENCY (%)	[1] STORAGE OF HIGH-LEVEL WASTE ($Millions)	[2] CLEAN DEMOLITION COST ($Millions)	UNIT COST of LLRW DISPOSAL ($/cubic foot)	LLRW BURIAL VOLUME (cubic yards)	[3] LLRW BURIAL COST ($Millions)
		HOPE CREEK 1	BWR	DECON	1990	437.316	25	n/a	27.43	n/a	81.03	23,510	84.50
		SALEM 1	PWR	DECON	1990	183 011	25	n/a	4.2	n/a	81.03	8,481	27.00
		SALEM 2	PWR	DECON	1990	273.143	25	n/a	16.12	n/a	81.03	8,587	28.80
23	ROCHESTER GAS & ELECTRIC	GINNA	PWR	DECON	1989	164.282	25	n/a	n/a	23.138	36.87	7,082	16.60
24	SMUD	RANCHO SECO	PWR	SAFSTOR	1991	328	19.02	n/a	18.14	46.778	179.00	7,381	36.71
25	SOUTH CAROLINA E&G	V.C. SUMMER	PWR	DECON	1990	228.798	25	n/a	n/a	51.413	81.03	6,488	21.00
26	SOUTHERN CAL. EDISON	SAN ONOFRE 1	PWR	SAFSTOR	1990	211.413	25	n/a	n/a	n/a	150.00	5,147	22.00
		SAN ONOFRE 2	PWR	DECON	1990	275.765	25	n/a	n/a	n/a	150.00	12,687	55.70
		SAN ONOFRE 3	PWR	DECON	1990	449.829	25	n/a	n/a	n/a	150.00	18,072	85.00
		SAN ONOFRE 1	PWR	SAFSTOR	1993	270.805	40	83.43	29.6	41.743	175-297	4,069	48.20
		SAN ONOFRE 2	PWR	DECON	1993	605.364	40	75.54	n/a	109.904		7,131	65.20
		SAN ONOFRE 3	PWR	DECON	1993	732.108	40	87.02	194	171.856		7,780	68.30
27	TEXAS UTILITIES	COMANCHE PEAK 1	PWR	DECON	1992	287.717	15.65	n/a	n/a	48.232	183.30	7,801	80.70
		COMANCHE PEAK 2	PWR	DECON	1992	362.603	15.79	n/a	n/a	87.204	183.30	12,320	84.00
28	UNION ELECTRIC	CALLAWAY	PWR	DECON	1990	335.556	25	n/a	n/a	67.474	182.00	8,735	80 80
				DECON	1993	371.612	18.58	22.14	n/a	58.842	250.00	7,482	88.80
29	VERMONT YANKEE NUCLEAR	VERMONT YANKEE	BWR	DECON	1993	312.738	18.55	24.67	7.8 (SAFSTOR)	44.117	180.00	6,154	48.90
30	VIRGINIA POWER	NORTH ANNA 1	PWR	DECON	1990	231.631	25	n/a	n/a	188.084	38.71	11,278	28.10
		NORTH ANNA 2	PWR	DECON	1990	236.348	25	n/a	n/a	181.815	38.71	12,387	28.70
		SURRY 1	PWR	DECON	1990	192.892	25	n/a	n/a	151.420	38.71	9,062	24.00
		SURRY 2	PWR	DECON	1990	241.8	25	n/a	n/a	188.882	38.71	11,268	27.70
31	WISCONSIN PUBLIC SERVICE	KEWAUNEE	PWR	DECON	1992	342.038	15.35	n/a	50.78	32.770	400.00	4,048	61.30
32	WOLF CREEK NUCLEAR OPER. CO.	WOLF CREEK	PWR	DECON	1993	368.79	18.58	22.51	n/a	82.474	300.00	7,480	78.10
33	WPPSS(Battelle for NRC)	WNP-2	BWR	DECON	1987	281.21	25	n/a	n/a	78.831	35.32	32,030	31.20
34	YANKEE ATOMIC ELECTRIC CO.	YANKEE ROWE	PWR	SAFSTOR	1992	247.117	18.38	n/a	56.49	14.398	372.00	3,747	41.47
			PWR	SAFSTOR	1994	370.071	13.47	n/a	73.45	n/a	441.00	4,204	90.08

Notes: n/a - not available
[1] - costs reported for dry storage only, i.e., capital expenditures and operating costs for an independent spent fuel storage installation following the actual decommissioning process; costs exclude contingency except where noted by [*]..
[2] - costs for non-radioactive demolition and site restoration include cascading costs and contingency
[3] - costs for low-level radioactive waste burial exclude contingency, however, costs do include disposal of GTCC material

2/9/95

Attachment I
Page 2 of 2

EXHIBIT DGB-9

<u>RESPONSE TO OCA-X-4</u>

G. T. Jones

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set X
Dated March 10, 1995
Docket No. R-00943271

Q.4. Is PP&L currently making payments to the Appalachian States Compact or a Pennsylvania LLRW Authority for development of an LLRW waste facility? If yes, please provide a schedule indicating what has been and will be spent by PP&L per year, and whether this money is expensed as an O&M cost. Also, provide the proportion of facility development costs that are assigned to PP&L.

A.4. PP&L did not make a payment in 1994 for the development of a low-level radioactive waste disposal facility. There is presently no legislation which mandates funding the project in 1995. Funding requirements necessary to develop the disposal facility were mandated by the Low-Level Radioactive Waste (LLRW) Disposal Regional Facility Act; LLRW Regional Facility Siting Fund. The legislation required the four utilities in Pennsylvania with nuclear power plants to pay $33,000,000 over a four-year period. In accordance with Pennsylvania law, PP&L was required to pay $1,526,728 in 1990, $1,963,638 in 1991, $1,526,728 in 1992 and $976,906 in 1993 for a total of $5,994,000. The funding revenue collected from PP&L is considered a miscellaneous deferred debit and represents approximately 18% of the required $33,000,000.

EXHIBIT DGB-10

DOE/SSDP-0081, SHIPPINGPORT STATION

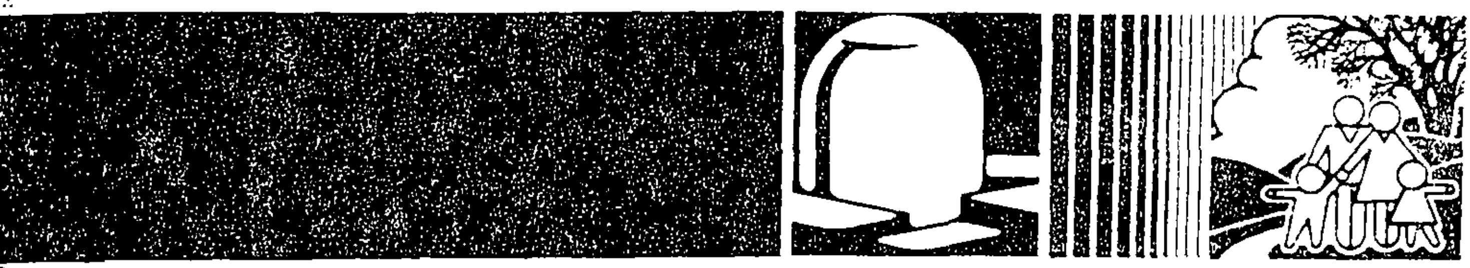
DECOMMISSIONING PROJECT, FINAL PROJECT REPORT, P. 6.

DECEMBER 1989

DOE SSDP-0081

OCT 18 1991

SHIPPINGPORT STATION DECOMMISSIONING PROJECT



FINAL PROJECT REPORT

SHIPPINGPORT STATION DECOMMISSIONING PROJECT

December 22, 1989

Prepared for the:

U.S. Department of Energy
Richland Operations Office
Shippingport Station Decommissioning Project Office

Prepared by:

Westinghouse Hanford Company
Shippingport Station Decommissioning Project Office
Post Office Box 323
Shippingport, Pennsylvania 15077
Under Contract DE-AC06-87RL10930

2.0 PROJECT MANAGEMENT

2.1 PROJECT COST AND SCHEDULE

SSDPO utilized DOE's Cost and Schedule Control System Criteria as the basis for complete integration of cost and schedule objectives and plans for project duration. SSDPO also applied DOE Order 4700.1 (Project Management System). This provided a uniform project control system for both prime contractors and the subcontractors and allowed for a totally integrated project wide system.

2.1.1 Project Summary Schedule

Overall Project Summary Schedule was based on an operations schedule planned to commence in September 1984 and to conclude in April 1990. Physical decommissioning occurred over forty six months from September 1985 to July 1989. Project physical decommissioning activities peaked in 1987. Figure 4 displays major project activities and major Project Milestones. Graph 1 is a display of manpower and progress over the life of the project. Graph 2 displays utilization of manpower and project functional components.

2.1.2 Project Costs

Total estimated cost including planning was $98.3 million. Final costs under-ran by $7.0 million for a total of $91.3 million. Figure 5 displays an overview of major physical decommissioning activities costs. Figure 6 is a display of the Work Breakdown Structure. Table 1 displays project costs by Work Breakdown Structure.

2.2 PROJECT RADIOLOGICAL CONTROLS

2.2.1 Radiological Control Program

Strict compliance with Radiological Control procedures was a key measure for minimizing occupational radioactivity exposure to As Low As Reasonably Achievable (ALARA) levels and for preventing spread of contamination. Radiological protection was accomplished by knowing, beforehand, the conditions of all work areas and other areas to be occupied on site. This was done by assigning Radiological Control Technicians (RCT) to perform surveys of each area. Before work could be performed in one of these areas a Radiation Work Permit (RWP) was prepared and approved. This document was based on the approved procedure for the work and a review of the survey results that had been obtained. The RWP specified the controls for personnel protection and provided a single point of reference for all subsequent measurements.

Where occupancy was conditional, the areas were roped off and posted. The various kinds of postings and their limiting conditions included:

Area Posting	Limiting condition definition
High radiation areas	Exposure more than 100 mR/hour
Radiation area	Exposure rate more than 1 mR/hour
Controlled Surface Contamination Area (CSCA)	Known loose contamination
Radiologically Controlled Area (RCA)	More than 1 mR/hour or possible CSCA conditions

EXHIBIT DGB-11

<u>RESPONSE TO OTS-RB-37</u>

G. T. Jones

PENNSYLVANIA POWER & LIGHT COMPANY
RESPONSE TO INTERROGATORIES
OF THE OFFICE OF TRIAL STAFF
DATED FEBRUARY 1, 1995
DOCKET NO. R-00943271

Q.OTS-RB-37. Has the Company done any studies or testing concerning the possibility of extending the operating license of either Susquehanna unit. Explain why or why not.

A.OTS-RB-37. PP&L has not performed any studies or testing regarding the extension of the operating license for the Susquehanna plant. The Company's current programs are designed to preserve the option for license renewal by maintaining the reliability and quality of the plant for the remainder of its current license period. PP&L has not performed any studies because of the current uncertainty regarding the NRC License Renewal Rule, which is under revision.

EXHIBIT DGB-12

ADJUSTMENTS TO SSES DECOMMISSIONING COSTS

PP&L BASE RATE CASE
DOCKET NO. R-00943271

ADJUSTMENTS TO SSES DECOMMISSIONING COST ESTIMATE

BASE COST PER TLG COST STUDY, DOCUMENT P02-25-001

ITEM	$ (000)	REMARKS/SOURCE
UNIT-1 TOTAL COST	350524	PAGE C-8
LESS NON-RAD COST	-44421	PAGE C-8
LESS PER'D 2 CNTCY	-45344	PAGE C-7
LESS PER'D 1 CNTCY	-3276	PAGE C-3
ADJUSTED UNIT-1 TOT	257483	
UNIT-2 TOTAL COST	453735	PAGE C-17
LESS NON-RAD COST	-80258	PAGE C-17
LESS PER'D 2 CNTCY	-52151	PAGE C-16
LESS PER'D 1 CNTCY	-5798	PAGE C-11
ADJUSTED UNIT-2 TOT	315528	
TOTAL BOTH UNITS	573011	

OCA STATEMENT NO. 5

5/3/95
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

FURTHER DIRECT TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON DEPRECIATION AND OTHER REVENUE ISSUES

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 1995

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

FURTHER DIRECT TESTIMONY
OF
DR. CHARLES E. JOHNSON

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland, 20904.

Q. ARE YOU THE SAME CHARLES E. JOHNSON WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR FURTHER DIRECT TESTIMONY?

A. I have been asked to review the depreciation expenses requested by PP&L in this filing and, if appropriate, to make recommended changes in the expense levels. I have also been asked to review the Company's treatment of economic development incentive/industrial development incentive credits and, if appropriate, to recommend an alternative treatment for the revenue lost from these credits.

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. After reviewing PP&L's proposed treatment of the pre-1989 investment in Susquehanna Nuclear Generating Station, I have concluded that the Company's proposal to levelize depreciation expense through the period ending December 31, 1998 should not be approved by the Commission. The Commission should continue with the current modified sinking fund (MSF) approach that was approved when these units went on line and was modified to satisfy the requirements of FAS 92.

Second, PP&L has calculated depreciation accruals on several of its coal units (namely Holtwood 17, Sunbury 1 through 4, and Martins Creek 1 and 2) and associated diesel and combustion turbine units to fully recover their capital by dates that are far earlier than the Company intends to retire these units. This is counter to the accepted depreciation practice of scheduling recovery of capital over the life of the asset until the asset is retired. Capital recovery for these units should be calculated based on the currently-expected retirement dates.

PP&L has requested a change in the treatment of depreciation for items of small value. The Company has requested that it be allowed to amortized these accounts over varying lives, rather than to maintain the accounting records necessary to perform life studies in the calculation of depreciation rates for these accounts. I recommend that the Commission approve such treatment of these accounts. However, the amortization periods PP&L has selected for these accounts do not comport with the current lives of these accounts and should not be used. I have recommended alternative amortization periods for these accounts.

Finally, PP&L has not provided evidence that ratepayers receive benefits equal to the cost of providing credits under the Economic Development Incentives and Industrial Development Incentive Programs. Absent such a showing, ratepayers should not bear the full burden of the costs of these programs and I recommend that the costs be shared equally between the Company and ratepayers.

III. DEPRECIATION

Levelized Depreciation for Susquehanna SES

Q. HAVE YOU REVIEWED PP&L'S PROPOSED CHANGE IN TREATMENT OF NUCLEAR PRODUCTION PLANT INSTALLED PRIOR TO JANUARY 1, 1989?

A. Yes. PP&L has proposed to change the manner in which it accrues depreciation on the Susquehanna Steam Electric Station (SSES) plant installed prior to January 1, 1989 for the period September 30, 1995 through December 31, 1998. The proposed change accelerates the recovery of capital in that 39-month period, compared to the current method of capital recovery.

Q. DOES THE EARLIER RECOVERY OF CAPITAL PROPOSED BY PP&L HAVE ANY EFFECT ON THE TEST YEAR LEVEL OF REVENUE?

A. Yes. The Company's proposed modification to the current capital recovery schedule increases test year expense by $30 million to $173 million. This change, therefore, increases the revenue being requested by about the same amount.

Q. SHOULD THE COMMISSION ADOPT PP&L'S PROPOSED CHANGE TO THE CAPITAL RECOVERY SCHEDULE FOR SSES?

A. No. When Susquehanna Unit 1 came on line in 1983, PP&L requested alternative treatment (use of the Modified Sinking Fund or MSF) for its capital recovery, which was approved by this Commission. Similar treatment was requested and approved for Unit 2 two years later. The Company's requested capital recovery has been accelerated already in response to FAS 92, so that the current recovery is at an earlier pace than originally requested by the Company.

That original schedule provided for a slower initial recovery of the capital invested in SSES than the standard treatment would have offered. One has to assume that whatever PP&L perceived about this non-standard treatment of capital recovery for Susquehanna, the Company felt that the recovery scheduled under the MSF was fair to both shareholders and ratepayers. The Company should have substantial reasons for requesting a change at this time. The previous change to the MSF was made in order to comply with FAS 92. No such similar compelling justification has been offered for this requested change.

Q. WHAT JUSTIFICATION HAS BEEN OFFERED BY THE COMPANY FOR ITS REQUESTED CHANGE IN CAPITAL RECOVERY FOR SSES?

A. The only justification provided by Company witness Hoch is that "... the Company's proposal will eliminate the large annual increases that arise under the current sinking fund method" and thereby "... enable the Company to minimize future base rate increase requests which would otherwise be necessary." [Statement 4, Page 15, lines 5-9]

Q. HOW LARGE ARE THE ANNUAL INCREASES IN DEPRECIATION ON SSES UNDER THE MODIFIED SINKING FUND IN THE PERIOD 1995 THROUGH 1998?

A. The increase in annual depreciation accrual from one year to the next never exceeds $20 million. Moreover, because net plant is declining each year, this $20 million is largely offset by the reduction in return on investment that is required.

I have prepared Exhibit___(CEJ-2), Schedule 1 to demonstrate the comparison of capital requirements associated with Susquehanna under the two approaches. Page 1 of Schedule 1 shows the return of capital and return on capital under the modified sinking fund and page 2 shows the same under the Company's proposed levelized approach. This schedule only covers the period from September 30, 1995 through September 30, 1998 and is only intended to be demonstrative of the difference between the two approaches, assuming revenues are set each year to reflect the change in rate base.

Note that the total recovery of capital would be relatively constant under the modified sinking fund. The increase in the depreciation accruals is almost exactly offset by the decrease in return on rate base. That is exactly what the MSF is calculated to do. The annual accrual is much like the portion of a mortgage payment that is principal, which is small in early years and increases over time. The return on rate base is much like the interest portion of the mortgage payment that decline over time and the sum of the two is a constant amount. Thus the "large annual increases" in the depreciation expense levels associated with Susquehanna are offset by what one must characterize as "large annual decreases" in required return on rate base associated with Susquehanna.

Q. WHAT IS OBJECTIONABLE ABOUT LEVELIZING THE CAPITAL RECOVERY OVER THE 39-MONTH PERIOD FOR USE IN THE TEST YEAR?

A. The major objections I have to the Company's proposal is that it only levelizes one aspect of capital recovery -- the depreciation accrual -- and does not levelize the other aspect of capital recovery -- return on capital invested. In fact, the sinking fund approach levelizes capital recovery when both aspects are considered. The problem with PP&L's approach is that it breaks the links between the two aspects of capital recovery -- return on capital and return of capital.

In normal ratemaking practice, there is a connection between depreciation accruals and rate base through the mechanism of providing a return on rate base (i.e.,) on adjusted net plant), which is gross plant less accumulated depreciation. The greater the accumulated depreciation over time, the lower the rate base and its return. This relationship is time dependent. If a method of depreciation is employed that accelerates depreciation, rate base decreases rapidly and every time a rate case is filed the amount of test year rate base is dependent on the depreciation accrued up to that time. A significant change in the size of the depreciation accrual would distort that relationship, at least for a period of time after the change.

A distortion of that kind can be seen in the Company's proposed levelized method. If the Commission were to adjust PP&L's rates each of the next four years using the 12-month period ending September 30 of each year as the test year, the capital recovery from SSES would decline each year, as shown on page 2 of Exhibit___ (CEJ-2), Schedule 1. Rates to customers would decline by over $50 million in that time. The total capital recovered for that period would be $1,889 million, compared to the $1,878 million that would be recovered if the MSF approach were used in the same four year period, not a large difference.

What is different is that if rates are not adjusted during this period, the capital recovered through rates (assuming the same level of other costs and sales) would be $499 million, the amount in the test year, each year for a total of $1,996 million during the four years, over $100 million more than if rates are set each year. This overrecovery is due to the inconsistent treatment of the two components of capital recovery.

Q. WHAT WOULD A CONSISTENT TREATMENT OF BOTH COMPONENTS OF CAPITAL RECOVERY BE?

A. One way of treating both components of capital recovery consistently would be to use the test year level for both.[1] A consistent alternative would be to levelize both the depreciation and rate base for ratemaking purposes. That is, if levelized depreciation of SSES is desired, then for ratemaking purposes, we should also levelize the SSES rate base over the same period.

Q. DO YOU RECOMMEND THAT BOTH RATE BASE AND THE DEPRECIATION ACCRUAL ASSOCIATED WITH SSES BE LEVELIZED?

A. No. Continuation of the current depreciation approach is a perfectly satisfactory manner of providing for PP&L's recovery of its capital.

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[1]In its filing, PP&L did not use the claimed amount of depreciation to calculate end of year rate base. Rate base for the test year is based on the depreciation PP&L projects it will book by 9/30/95.

Q. WHAT IS THE PROPER LEVEL OF SUSQUEHANNA DEPRECIATION TO INCLUDE IN TEST YEAR EXPENSES?

A. The proper level of depreciation for the Susquehanna SES to include in expenses for the test year is $152,777,006, in place of the requested $181,920,269. On a jurisdictional basis, the difference between the Company's requested level and the corrected level is $22,864,760. I have provided this value to OCA accounting witness Catlin for use in his determination of revenue.

Q. DOES THE OCA'S PROPOSED DISALLOWANCE OF AN EQUITY RETURN ON SUSQUEHANNA 2 AFFECT YOUR RECOMMENDATION?

A. No. First, the justification would still be applicable to Susquehanna Unit 1. Second, the Company's request was based on full return on all nuclear investment and if the Company prevails on that issue, it has no justifiable reason for accelerating the recovery of the nuclear investment.

Third, even if the equity portion of the return on Susquehanna 2 is disallowed, that only diminishes the amount of return and does not negate the fundamental argument. The primary effect of levelizing depreciation on SSES is to increase expense levels and the only justification provided by the Company is that future rate cases might be deferred. It still is the Company's burden to show that such a change is warranted and the Company has not done so.

Advance of Deactivation Dates

Q. HAS PP&L ADVANCED THE DECOMMISSIONING DATES FOR ANY OF ITS GENERATING UNITS FROM THOSE DATES GIVEN IN THE COMPANY'S MOST RECENT FIVE-YEAR UPGRADE PLAN?

A. Yes. PP&L has advanced the decommissioning dates for Holtwood 17 steam plant from 2009 to 2003, Martins Creek Units 1 and 2 from 2015 to 2003 and Sunbury 1, 2, 3 and 4 from 2010 to 2003. In addition, the combustion turbines and diesel units at Sunbury are advanced from 2010 to 2003 and combustion turbines and diesel units at Martins Creek are advanced from 2015 to 2010, which is the currently-scheduled deactivation date for Martins Creek Steam Units 3 and 4.

Q. DOES THE ADVANCE OF THE DEACTIVATION DATES FOR THESE UNITS INCREASE THE DEPRECIATION ACCRUAL REQUESTED BY THE COMPANY?

A. Yes. The depreciation accruals for these generating units increases by approximately $19 million, from $18,004,884 to $36,748,687.

Q. WHAT IS THE BASIS FOR THE COMPANY'S ADVANCEMENT OF THE DEACTIVATION DATES OF THESE UNITS?

A. The Company's witness Krall testified that the Company made a decision to "reflect the <u>possibility</u> that they would be retired earlier in the depreciation schedule" and that the only place that this possibility is set forth is in witness Krall's testimony. [Tr. 188] [Emphasis added.] He also testified that the Company does not plan to retire those units in 2003. [Tr. 176] It seemed clear from his testimony that PP&L has set the earlier deactivation dates solely for the purpose of calculating depreciation accruals in this rate case. It is also clear from Mr. Krall's testimony that the 2003 deactivation dates for the units are not the dates on which PP&L intends to retire these units or to begin to dismantle them.

Q. IS IT APPROPRIATE TO ADVANCE THE DEACTIVATION DATES AS REQUESTED BY PP&L?

A. No. It is not appropriate to advance the deactivation dates as requested by PP&L. As I will discuss subsequently, no thorough study of these units has been made and the Company has no sound engineering or economic basis for taking such action. Moreover, it is not clear what the Company means by deactivating the plants, but it does not mean retiring them. PP&L wants to recover the undepreciated balance for these plants by 2003, even though it has no plans to retire them at that time.

It is a general principle of depreciation accounting that the capital invested in plant is to be recovered over the useful life of the plant and at the time of its retirement, all capital is to have been recovered. Exceptions exist, of course, where it doesn't work out that way, but the general objective of performing depreciation studies is to determine appropriate service lives and other parameters so as to be able to accrue the correct amount of depreciation each year that will result in the full and complete recovery of the capital at the time of retirement. If the Company does not intend to retire these units in 2003, it is improper to request capital recovery by that date.

Q. WHAT ANALYSIS HAS PP&L PERFORMED IN JUSTIFICATION OF ADVANCING THE DEACTIVATION DATES FOR THESE UNITS?

A. The Company has performed no analysis of any kind to justify advancing the deactivation dates of Sunbury, Martins Creek and Holtwood. Mr. Krall responded that "the Five-Year Upgrade Plan for Coal-Fired Generation was the starting point for PP&L's proposed retirement dates for these units." Beyond that, no specific analysis or document was identified and he has testified that none exists.

Q. ARE THESE UNITS DISCUSSED IN THE FIVE-YEAR UPGRADE PLAN?

A. Yes. Sunbury, Martins Creek and Holtwood are discussed in Sections 5, 6 and 7, respectively. Subsection 5.2 addresses the potential for continued operation and upgrading of Sunbury, with similar discussions in 6.2 and 7.2 for Martins Creek and Holtwood. The last paragraph of Subsection 5.2 states "Based on these analyses, it is prudent to make those investments which are necessary to continue the operation of Sunbury through at least 2013. This means that it is also prudent to "pursue improve ments which would cover their costs by 2013." Additions to these plants have been made and budgeted on that basis. Some of these expenditures are not reasonable for a planned 2003 retirement.

Q. WHEN WAS THE FIVE-YEAR UPGRADE PLAN PREPARED?

A. The Five-Year Upgrade Plan is dated May 2, 1994 and was provided in response to OCA IV, Q. 85.

Q. WAS ADVANCING THE DEACTIVATION DATES OF ANY OF THESE UNITS ADDRESSED IN THE 1995-1996 BUDGET?

A. No. The 1995-1996 Budget was provided as Exhibit DAK-2 and Section F, PP&L's resources/Obligations contains the statement "PP&L currently has no current plans to retire any other existing generating units for the period 1994-2013, although this could change as the utility industry environment changes."

Q. WHEN WAS THE 1995-1996 BUDGET PREPARED?

A. The 1995-1996 Budget is dated October 1994.

Q. WHAT JUSTIFICATION HAS PP&L GIVEN FOR ADVANCING THE DEACTIVATION DATES OF THE GENERATING UNITS IDENTIFIED?

A. The combustion turbine and diesel units are used for black start, according to the Company and should be taken out of service when the steam units are retired. Company witness Krall identified four reasons for advancing the deactivation dates of the steam units. They are:

(1) The units are old and have in-service dates of from 1949 to 1954,
(2) These units are relatively less efficient than newer generating stations,
(3) the cost of meeting environmental requirement is great, and
(4) these generating units are small.

[Statement 5, page 9]

Q. WERE THE FOUR REASONS GIVEN BY MR. KRALL BASED ON NEW INFORMATION THAT WAS NOT AVAILABLE AT THE TIME THE FIVE YEAR UPGRADE PLAN WAS PREPARED?

A. No. Nothing has been identified by Mr. Krall that was not already known at the time the Five-Year Upgrade Plan was prepared. That these generating units are old, small and less efficient generating units has not changed in the past year. They were old, small and less efficient than other generating plants a year ago. As for environmental costs, some of these were included in the development of the Five-Year Upgrade Plan and the ones that weren't included were and still are too speculative to be able to include in any analysis.

Q. DO YOU RECOMMEND A MODIFICATION TO THE COMPANY'S DEPRECIATION ACCRUAL FOR THE SUNBURY, HOLTWOOD AND MARTINS CREEK STATIONS?

A. Yes. In response to OCA XIV, Q. 1, PP&L provided the calculation of accruals for these generating units under the original deactivation dates. This is a difference of $18,743,803 on a total company basis, and on a Pennsylvania jurisdictional basis the difference is $15,274,409. I have provided this value to OCA accounting witness Catlin for use in calculating the revenue requirements.

<u>Amortization of Small Value Items</u>

Q. HAS PP&L PROPOSED A DIFFERENT TREATMENT OF ITEMS OF SMALL VALUE FROM THE TREATMENT FOR THESE ITEMS IN THE PAST?

A. Yes. PP&L has proposed to discontinue keeping the kind of detailed record necessary for calculating depreciation accruals for approximately $55 million of plant and to amortize those accounts over varying periods.

Q. IS IT APPROPRIATE TO AMORTIZE ITEMS OF SMALL VALUE?

A. I have no reason to doubt the Company's claim that the recordkeeping required to calculate depreciation for these accounts is an unnecessary burden on the Company and that it is reasonable to establish lives over which the assets in these accounts be amortized. For the very reason that data will not be maintained and available in the future for examining the propriety of the amortization rates, it is especially important to perform a thorough review of the proposed amortization periods for each of these accounts now and set amortization periods reasonably accurately. It will not be possible to do so in the future, because the data will not have been collected to do so.

Q. HAVE YOU PERFORMED A REVIEW OF THE PROPOSED AMORTIZATION PERIODS FOR THE ACCOUNTS PP&L PROPOSES TO AMORTIZE?

A. Yes. I have thoroughly reviewed the proposed amortization periods for accounts 391.2 (furniture), 391.4 (mechanical equipment), 391.6 (computer equipment-general), 393 (stores equipment), 394 (tools and work equipment), 395 (laboratory equipment), and 398 (miscellaneous equipment). For every one of the accounts except one, the resulting amortization amount requested by the Company is greater than or equal to the accrual under depreciation rates now in effect.

Q. ARE THE HIGHER ACCRUALS JUSTIFIED?

A. The proposed accruals for two of the accounts are not unreasonable, meaning that the proposed amortization periods are reasonably close to those I would select, but for the remaining accounts, the amortization periods are far too short.

Q. FOR WHICH ACCOUNTS ARE THE AMORTIZATION PERIODS TOO SHORT?

A. The amortization periods proposed for accounts 391.2, 394, 395 and 398 are too short, and the amortization periods proposed for accounts 391.6 and 393 are acceptable.

Q. PLEASE EXPLAIN WHY THE AMORTIZATION PERIOD PROPOSED BY PP&L FOR ACCOUNT 391.2 IS TOO SHORT.

A. PP&L has proposed a 20 year amortization for account 391.2 (Furniture). In response to a request for information supporting this proposed amortization period (OCA III, Q. 8), PP&L provided information about the accounts that are to be amortized. There are several features of this data that suggest a longer amortization than 20 years for furniture and nothing on which to base a 20 year amortization.

First, the Company compared the retirement data for this account with several standard curves used in depreciation analysis, known as Iowa curves. The curve that best fit all the data was the Iowa curve designated S1-38.7, being a Symmetric curve with a 38.7 year average service life. With some of the data excluded, the curve of best fit had an average service life of 40.1 years. These analyses suggest that an amortization period of around 40 years is more appropriate than a 20 year amortization period.

A second observation, based on the retirement data provided, is that over half of all the furniture placed in this account was still in use 44 years later. In fact, 98.18 percent of all furniture placed ten years earlier was still in use and 89.44 percent of that placed 20 years earlier was still in use. This observation certainly indicates that the life of assets in this account is greater than 20 years and that the amortization period for the account should be greater than 20 years.

Third, for all retirements during the 20-year period 1972-1991, the average age of plant retired is 30.0 years. This means that during the most recent 20-year period, the average age of plant being retired was 30 years. For a growing account, this suggests a longer life than 30 years.

There is nothing in any of this data to suggest a 20-year amortization period for furniture. According to Company witness Hoch, the derivation of the 20-year amortization period was from discussions with individuals in the PP&L facilities department who gave their best knowledge of "how long furniture should last." [Tr. 141] There is no indication that these individuals were knowledgeable about how long furniture actually had lasted at PP&L or about the dispersion of retirements for this account.

Q. DO YOU RECOMMEND A DIFFERENT AMORTIZATION PERIOD FOR ACCOUNT 391.2 -- FURNITURE?

A. Yes I propose an amortization period of 30 years for this account.

Q. DO YOU RECOMMEND DIFFERENT AMORTIZATION PERIODS FROM THE COMPANY FOR OTHER ACCOUNTS.

A. Yes. I have proposed that longer amortization periods be used for accounts 391.2, 391.4, 394.0, 395 and 398 than the amortization periods requested by PP&L. The amortization periods I recommend for those accounts are shown in Exhibit___ (CEJ-2), Schedule 2 compared to the amortization periods requested by PP&L.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I have reviewed all of the data provided by PP&L about these accounts and find that in each instance, the data support longer amortization periods than requested by the Company. The current lives for these accounts are shown on Exhibit___(CEJ-2), Schedule 2, by way of comparing the current lives with PP&L's requested lives and my proposed lives.

In Exhibit___(CEJ-2), Schedule 3, I have provided, for each account, a summary of the information that was described for account 391.2 above. The average age of retirements, life for the curve of best fit and the number of years when over 50 percent of the account still survived are shown on that Exhibit.

Finally, I compared the amount of depreciation booked in these accounts during the test year with the amount claimed by PP&L under their proposed amortization and show these in Exhibit___(CEJ-2), Schedule 3. Again, if we look at account 391.2, furniture, we see a great disparity in the amount booked and the amount claimed by PP&L. By examining the plant in the account, $16,044,199 and the reserve, $5,318,831, we see that the Company's requested annual accrual of $2,068,390 would completely recover the unrecovered balance in five years, not in the requested 20, or the more appropriate 40. I have examined each of these accounts and estimated an appropriate level to include in test year expenses. My recommended levels are shown in Exhibit___(CEJ-2), Schedule, 3 page 2.

Q. DO YOUR RECOMMENDATIONS AFFECT THE TEST YEAR LEVEL OF DEPRECIATION EXPENSE FOR THESE ACCOUNTS?

A. Yes. Excluding several of these accounts that are charged to clearing accounts, the Company has requested $4.4 million for the test year accrual for these accounts. The amount PP&L projects to book during the test year for these accounts is $1.4 million. I recommend that the test year level of expense for depreciation accrual be $1,244,850, or $3,141,268 less than requested by PP&L. The Pennsylvania jurisdictional amount is $2,715,745.

IV. EDI/IDI CREDITS

Q. HAS PP&L REQUESTED RECOVERY OF THE ECONOMIC DEVELOPMENT INCENTIVES AND THE INDUSTRIAL DEVELOPMENT INCENTIVES?

A. Yes. PP&L has included recovery of $23,705,606 in Economic Development Incentives (EDI) and $1,625,464 in Industrial Development Incentives (IDI).

Q. HOW HAVE THE CREDITS BEEN INCLUDED IN THE REVENUE REQUEST?

A. The credits reduce the current revenue from the customers receiving the credits, so the revenue from these customers incorporates the credits. The class revenue for the classes with customers receiving EDI/IDI credits therefore, implicitly includes the credits.

Q. IS IT APPROPRIATE FOR PP&L TO RECOVER REVENUES FROM RATEPAYERS TO PROVIDE THE EDI/IDI CREDITS?

A. No. PP&L should be required to show that other ratepayers benefit from the expenditure of the $25 million before being allowed to recover all of the expense from ratepayers.

Q. DID COMPANY WITNESS KASPER SHOW THAT OTHER RATEPAYERS BENEFIT FROM THE EDI/IDI PROGRAMS?

A. No. In Statement 8, at page 19, Mr. Kasper claimed that his analysis showed that other ratepayers benefit from the EDI/IDI programs, but his analysis merely shows that absent the sales and associated revenues from certain customers, the cost of service would be higher for remaining customers. The same would be true absent the sales and associated revenues from any group of customers at any revenue level, so long as fuel was covered by that revenue. Under such an argument, PP&L could justify selling power to any class of customers it wanted at any price above the cost of fuel and claim that such sales benefited other customers.

PP&L claimed that 300 million KWH of sales would have been lost without the EDI/IDI programs. This assumes that every KWH of sales for which EDI/IDI credits were provided would have been lost at the standard rate and that there are no free riders. PP&L has made no attempt to show that this is the case. It simply claims that these sales would not have been made absent the EDI/IDI credits.

Q. DO YOU CLAIM THAT RATEPAYERS RECEIVED NO BENEFIT FROM THESE PROGRAMS?

A. No. I only claim that there is no evidence that the other ratepayers benefits were as large as the cost of the EDI/IDI programs. It was not demonstrated that any benefit received by ratepayers was equal to the full cost of the programs. Absent proof that the ratepayers received benefits of that magnitude, they should not be responsible for bearing the entire cost of the incentive programs.

Q. DID SHAREHOLDERS BENEFIT FROM THE EXISTENCE OF THE EDI/IDI PROGRAMS?

A. It is possible that shareholders benefitted from the existence of these programs in the period from 1987 up to now, but a portion of any benefits have come from other ratepayers. Assuming that the full 300 million KWH were retained by the existence of the programs and would otherwise have been lost to PP&L, any benefit to shareholders would have been the net revenue produced by these customers. However, these benefits came at a cost to other ratepayers during that period.

These additional sales imposed fuel costs on PP&L equal to the marginal costs on the system. Because the marginal costs are above the average cost of fuel, the additional sales raised the average cost of fuel to all other ratepayers to recover those additional costs, but only the average cost of fuel is recovered from the EDI/IDI customers. This new average cost of fuel was passed through the ECR to other ratepayers, so their costs increased as a result of the EDI/IDI programs, while shareholders received any benefits from the programs.

The EDI program is closed, but PP&L proposes to leave the IDI program open through 1997. This means any benefits from additional sales made under the program will flow to shareholders, at the same time existing customers will incur additional costs, as they did before. Thus, not only will other ratepayers have to pay the cost of providing the credits for the level of EDI/IDI programs in the test year, their fuel costs will be higher as a result of both current and any future sales to customers under the EDI/IDI programs.

Q. HOW SHOULD THE RECOVERY OF THE EDI/IDI PROGRAM COSTS BE RECOVERED?

A. I recommend that the cost of the EDI/IDI programs be shared equally between the ratepayers and the shareholders of PP&L. On that basis, I recommend that the Company's current revenues be increased by $12,665,535. I have provided this value to OCA revenue requirements witness Catlin.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SCHEDULES ACCOMPANYING THE

FURTHER DIRECT TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON DEPRECIATION AND OTHER REVENUE ISSUES

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 1995

PAPUC Docket No. R-00943271
Exhibit___ (CEJ-2)
Schedule 1
Page 1 of 2

PENNSYLVANIA POWER AND LIGHT COMPANY

Recovery of Capital Invested in Susquehanna Steam Electric Station
Modified Sinking Fund
($ Millions)

Year Ending	Plant in Service	Depreciation Reserve	Net Plant	Return at 10.17%	Depreciation Accrual	Total Capital Recovered
9/30/95	4,039	836	3,204	326	142	468
9/30/96	4,039	978	3,061	311	157	469
9/30/97	4,039	1,136	2,904	295	175	470
9/30/98	4,039	1,310	2,729	278	194	471
Total						1,878

PENNSYLVANIA POWER AND LIGHT COMPANY

Recovery of Capital Invested in Susquehanna Steam Electric Station
PP&L Levelized Approach
($ Millions)

Year Ending	Plant in Service	Depreciation Reserve	Net Plant	Return at 10.17%	Depreciation Accrual	Total Capital Recovered
9/30/95	4,039	836	3,204	326	173	499
9/30/96	4,039	1,008	3,031	308	173	481
9/30/97	4,039	1,181	2,858	291	173	463
9/30/98	4,039	1,354	2,685	273	173	446
Total						1,889

PENNSYLVANIA POWER AND LIGHT COMPANY

Amortization Periods
(Years)

	Account	Requested by PP&L	Current Life	Proposed by OCA
391.2	Furniture	20	34	30
391.4	Mechanical Equipment	15	20	20
391.6	General Computers	10	20	10
393.0	Stores	30	30	30
394.0	Tools - L&S Line Crews	20	45	40
394.4	Tools - Construction	20	34	30
394.6	Tools - Other	20	39	35
394.8	Garage Equipment	20	25	35
395.0	Laboratory Equipment	15	45	40
398.0	Miscellaneous Equipment	25	38	35

Source: Attachment V-B-2, page 10 and OCA XI, Q. 6.

PENNSYLVANIA POWER AND LIGHT COMPANY

Age Estimates

	Account	Average Age of Retirements	Curve Life of Best Fit	Years Where 50% Survive
391.2	Furniture	30.0[1]	38.7	44
391.4	Mechanical Equipment	7.7[2]	20.3	>16
391.6	General Computers	6.5[3]	8.5	9
393.0	Stores	28.0[1]	34.2	32
394.0	Tools - L&S Line Crews	16.8[4]	32.3	30
394.4	Tools - Construction			
394.6	Tools - Other			
394.8	Garage Equipment			
395.0	Laboratory Equipment	13.0[5]	19.2	18
398.0	Miscellaneous Equipment	17.1[1]	29.5	30

Source: OCA III, Q. 8.
[1]Experience years 1972-1991.
[2]Experience years 1977-1992.
[3]Experience years 1983-1992.
[4]Experience years 1982-1991.
[5]Experience years 1972-1992.

PENNSYLVANIA POWER AND LIGHT COMPANY

Amortization Levels

	Account	Booked in Test Year	Claimed By PP&L	Proposed By OCA
391.2	Furniture	455,288	2,068,390	534,807
391.4	Mechanical Equipment	100,795	352,409	110,260
391.6	General Computers	502,768	189,798	223,661
393.0	Stores	64,501	81,484	71,621
394.0	Tools - L&S Line Crews	*	*	*
394.4	Tools - Construction	*	*	*
394.6	Tools - Other	91,521	424,165	94,970
394.8	Garage Equipment	*	*	*
395.0	Laboratory Equipment	107,629	850,080	113,139
398.0	Miscellaneous Equipment	93,521	419,796	96,393
	Total	1,416,023	4,386,118	1,244,850

*These accounts were changed to clearing accounts.

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OCA Statement No. 6

5/3/95
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCUMENT FOLDER

DOCKETED
MAY 08 1995

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 1995

EXETER
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

Direct Testimony of Thomas S. Catlin

Introduction

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

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

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

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

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

In September 1981, I accepted a position as a utility rates analyst with Exeter Associates, Inc. Since that time, I have continued to be involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have been extensively involved in the review and analysis of utility rate filings, focusing primarily on revenue requirements determination. I have also addressed class cost of service and rate design. This work has involved natural gas, telephone and water utilities as well as electric companies.

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

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

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

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the OCA to determine the level of revenues which Pennsylvania Power & Light Company (PP&L or the Company) should be awarded in this proceeding. In this testimony, I present my findings regarding PP&L's test year rate base and net operating income at present rates. Based on these amounts, I have determined the additional revenues which are required to generate the overall rate of return on rate base recommended by my associate, Mr. Matthew I. Kahal, on behalf of the OCA. In developing my recommendation, I have incorporated certain adjustments sponsored by my associates, Mr. Kahal and Dr. Charles Johnson, as well as by the OCA's expert on nuclear issues, Mr. Dale Bridenbaugh.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Schedules TSC-1 through TSC-27 are attached to my testimony. These schedules present my findings and recommendations regarding PP&L's test year revenue requirements.

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE COMPANY'S REVENUE REQUIREMENT.

A. As shown on Schedule TSC-1, I have determined the Company has a Pennsylvania jurisdictional revenue surplus of $73,121,000 for the test year ended September 30,

1995. This is the amount by which revenues exceed those required to generate an overall rate of return of 9.33 percent after accounting for the OCA's adjustments to PP&L's claimed rate base and operating income. The return of 9.33 percent represents Mr. Kahal's finding regarding the Company's overall rate of return.

The pro forma return at proposed rates shown on page 1 of Schedule TSC-1 is less than 9.33 percent. This is due to Mr. Kahal's adjustment to disallow the common equity return on PP&L's jurisdictional investment in Susquehanna Unit 2. The calculation of the revenue surplus recognizing the disallowance of the common equity return on Susquehanna Unit 2 is shown on page 2 of Schedule TSC-1.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the remainder of my testimony, I document and explain each of the adjustments to rate base and operating income which I have made to arrive at the test year revenue surplus shown on Schedule TSC-1. I will first address rate base and then net income.

Rate Base

Q. HAVE YOU MADE A DETERMINATION OF THE RATE BASE UPON WHICH PP&L SHOULD BE ALLOWED TO EARN A RETURN?

A. Yes. As shown on Schedule TSC-2, I have determined PP&L's test year jurisdictional rate base to be $4,896,679,000. This represents a reduction of $120,499,000 compared to the Company's claimed test year rate base of $5,017,178,000. The adjustments to which the difference is attributable are summarized on page 1 of Schedule TSC-2. Page 2 of Schedule TSC-2 provides a breakdown of PP&L's rate base by component after recognizing these adjustments.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEDUCT THE BALANCE OF THE ACCRUED PENSION LIABILITY FROM RATE BASE.

A. The accrued pension liability which is reflected on PP&L's books represents the difference between the pension costs which have been reflected on PP&L's books and the Company's contributions to its pension fund since the implementation of Statement of Financial Accounting Standard (SFAS) No. 87 in 1987. Since 1987, the pension costs recorded on the Company's books have either already been recovered from ratepayers as an expense in the year in which they were recorded or are being recovered as a component of the capitalized overheads included in the cost of plant in service. Therefore, the accrued pension liability represents funds that have been recovered from ratepayers,[1] but which have not been contributed to the pension fund by the Company. Accordingly, the balance of the accrued pension liability should be deducted from rate base.

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[1]Although capitalized pension costs have not yet been fully recovered, PP&L is separately recovering these amounts through depreciation expense and the undepreciated balance is part of rate base. As a result, the effect is the same as though they had already been recovered.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT ON RATE BASE?

A. As shown on Schedule TSC-3, this adjustment reduces total Company rate base by $85,537,000 and Pennsylvania jurisdictional rate base by $74,034,000. In calculating the balance of accrued pensions to be deducted from rate base as of September 30, 1995, I have reflected the recommendation discussed later in my testimony that the test year pension accrual be set at zero dollars. I have also reflected the test year amortization of the pension supplement associated with the Voluntary Early Retirement Program (VERP). To derive the net rate base deduction for accrued pensions, I have netted out the negative deferred income taxes associated with accrued pensions. These deferred income taxes result from the fact that pension expense is not tax deductible until the contribution to the pension fund is actually made.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE BALANCE OF ACCUMULATED DEFERRED INCOME TAXES DEDUCTED FROM RATE BASE?

A. In developing its rate base claim, PP&L has only recognized the balances of accumulated deferred income taxes (ADIT) due to accelerated depreciation and ADIT related to test power at Martin's Creek and Susquehanna as deductions from rate base. In addition to accounting for the balance of ADIT associated with my adjustment for accrued but unpaid pensions, I am proposing to adjust the balance of ADIT which is deducted from rate balance to reflect the balance of accumulated deferred income taxes associated with the loss on reacquired debt. As shown on Schedule TSC-4, this adjustment reduces total Company rate base by $47,863,000 and reduces Pennsylvania jurisdictional rate base by $40,838,000.

Q. WHY IS YOUR ADJUSTMENT TO RECOGNIZE THE ADIT ASSOCIATED WITH THE LOSS ON REACQUIRED DEBT AS A DEDUCTION FROM RATE BASE NECESSARY?

A. The balance of ADIT associated with the loss on reacquired debt arises because PP&L received a tax deduction for the loss at the time it was incurred. For accounting purposes, however, the loss was not written off at that time. Instead, the loss was deferred and is being amortized over time as a component of interest expense. As such, the balance of ADIT associated with the loss represents the amount of non-investor supplied, zero cost capital which is available to the Company as a result of tax benefits which were realized by deducting the loss on reacquired debt immediately when it was incurred.

For ratemaking purposes, the weighted cost of debt has been calculated to fully account for the loss on reacquired debt. This has been accomplished by both including the amortization of the loss as an interest cost and deducting the unamortized balance of the loss from the balance of outstanding debt used to calculate the weighted cost. However, nowhere in its calculations has PP&L recognized that it received an immediate tax benefit for the loss which served as a source of cost-free capital. Therefore, deducting the balance of ADIT on reacquired debt from rate base is necessary to recognize this balance as a source of non-investor supplied capital.

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE BALANCE OF PREPAYMENTS?

A. I have made three adjustments to the balance of prepayments included in rate base by PP&L. First, I have eliminated the balance of prepaid insurance. Second, I have increased the balance for the prepaid PUC annual assessment to properly reflect the annual average balance. Third, I have adjusted the balance of other prepayments to exclude the effects of a one-day prepayment of interest and preferred dividends.

Q. PLEASE EXPLAIN THE BASIS FOR EACH OF THESE ADJUSTMENTS TO THE BALANCE OF PREPAYMENTS.

A. PP&L has included the 13-month average balance of prepaid insurance in rate base in order to recognize the fact that premiums for many of its insurance policies must be made at or near the beginning of the time period covered by the policy. The problem with this treatment is that the Company has also reflected the fact that its insurance premiums must be prepaid in its lead-lag cash working capital analysis. That is, in the lead-lag study, the Company has calculated that its insurance premiums are paid 134 days in advance. In calculating this payment lead, PP&L included the same policies which are reflected in the balance of prepayments. Therefore, to avoid this double count, I have removed the balance of prepaid insurance from rate base.

The adjustment to increase the balance for the prepaid PUC annual assessment is necessary because PP&L reclassified the balance from prepaid taxes to a separate prepaid expense subaccount in September 1994. As a result, the Company's claimed balance of prepaid expenses, which is based on the actual historic test year balance, reflects only one month's balance for the PUC annual assessment. I have increased the balance of prepayments to reflect the balances for the prepaid PUC assessment for all 13 months.

As shown on page 3 of Schedule C-4 in Exhibit Historic 1 and Future 1, the balance of "other" prepayments normally ranges from a $200,000 to $2.7 million. However, in March 1994, the month end balance jumped to $68.1 million. This occurred because PP&L made a deposit to its bond interest and preferred dividend payment accounts on March 31, 1994 to cover payments due on April 1, 1994. The deposits had to be made one day ahead of time because of the Good Friday holiday on April 1, 1994. By recording this one-day advance payment as a prepayment and including it in the 13-month average, PP&L has increased the balance of other prepayments by almost $5.2 million. This is inappropriate because the advance payment only existed for one day and because this one-day advance payment was not a normal event. Therefore, I have adjusted the balance of "other" prepayments to exclude the effects of this prepayment of interest and preferred dividends.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE EFFECTS OF YOUR ADJUSTMENTS TO THE BALANCE OF PREPAYMENTS?

A. Yes. Schedule TSC-5 summarizes my adjustments to the balance of prepayments. As shown there, the net effect of my adjustments is to reduce the total Company balance of prepayments by $9,308,000 and to reduce the Pennsylvania jurisdictional balance by $7,609,000.

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO PP&L'S CASH WORKING CAPITAL CLAIM?

A. I have made four changes to the lead-lag analysis utilized by PP&L to calculate its cash working capital claim. First, I have revised the composite revenue lag to correct the lag utilized for 20-day accounts. Second, I have revised the O&M expense lag to account for the effects of recognizing Clean Air Act Amendment (CAAA) permit fees and interest on customer deposits as separate expense items and to exclude an invoice for a capitalized expense from the calculation of the lag. Third, I have revised the payment lags for interest on long-term debt and preferred dividends to be consistent with a 365-day year. Finally, I have revised the amounts of expenses and taxes incorporated in the study to reflect the OCA's adjustments to PP&L's claimed expenses and taxes.

Q. PLEASE EXPLAIN THE ADJUSTMENT WHICH YOU HAVE MADE TO THE COMPOSITE REVENUE LAG.

A. PP&L has developed a composite revenue lag based on an analysis of the lag in the receipts of each component of its overall revenues. In response to OTS-RE-19D, PP&L indicated that the revenue lag associated with accounts for which the payment due date is 20 days (20-day accounts) was inadvertently overstated by two days. Therefore, I have revised the composite revenue lag to reflect the correction of the 20-day account lag. This correction has the effect of reducing the overall revenue lag from the 35.6 days used by PP&L to 35.0 days.

Q. PLEASE EXPLAIN HOW PP&L TREATED CAAA PERMIT FEES AND INTEREST ON CUSTOMER DEPOSITS IN DETERMINING ITS O&M EXPENSE PAYMENT LAG.

A. In the same manner in which it developed a composite revenue lag, PP&L developed an overall O&M expense payment lag by analyzing the payment patterns for various components of O&M expense. In developing this composite lag, neither CAAA permit fees nor interest on customer deposits was recognized separately. Instead, both CAAA permit fees and interest on customer deposits were included as a component of "other" O&M and assigned a payment lag of 32 days. In addition, neither item was considered in determining the payment lag of 32 days applied to other O&M.

Q. WHY ARE YOU PROPOSING TO TREAT CAAA PERMIT FEES AND INTEREST ON CUSTOMER DEPOSITS AS SEPARATE EXPENSE ITEMS IN DETERMINING THE COMPOSITE O&M EXPENSE PAYMENT LAG?

A. The CAAA permit fees which PP&L and other utilities pay to the Commonwealth of Pennsylvania for a given calendar year are due prior to September 1 of the following year. For example, on August 26, 1994, PP&L paid approximately $848,000 of

CAAA permit fees applicable to calendar year 1993. As a result, the payment lag for CAAA permit fees is almost 14 months. This is clearly not a typical lag, particularly for such a large expense. Therefore, the expense payment lag of 32 days for other O&M is simply not representative and appropriate for CAAA permit fees. Therefore, I recalculated the composite O&M expense payment lag by separately recognizing these permit fees with a lag of 421 days based on the August 26 payment date used in 1994.

Interest on customer deposits is paid annually and, as a result, the average payment lag associated with interest on customer deposits is 182.5 days. Although the amount of the interest on customer deposits is relatively small, it is appropriate that ratepayers receive recognition that interest on their deposits is only paid annually. Therefore, I have recalculated the composite O&M expense lag by separately recognizing interest on customer deposits with a 183 (rounded) day lag. This net effect of my adjustments to separately recognize CAAA permit fees and interest on customer deposits is to increase the composite expense payment lag calculated on Schedule C-4 of PP&L Exhibit Historic 1 from 30.9 days to 31.1 days.

Q. WHAT ADJUSTMENT HAVE YOU MADE RELATED TO AN INVOICE FOR A CAPITALIZED ITEM?

A. PP&L developed the 32 day lag for other O&M expenses based on a sample of the invoices paid in the three months ended July 31, 1994. One of the invoices which was included in this sample was a relatively large invoice for a purchase of a pump system for the Sunbury plant which was originally expensed and later corrected and capitalized. Because it was a capital cost and not an O&M expense, this invoice should not be included in determining the O&M expense lag. Therefore, I have removed this invoice from the calculation of the other O&M lag. This has the effect of increasing the other O&M lag from 32 to 33 days and further increasing the composite O&M expense from the 31.1 days discussed above to 31.4 days.

Q. WOULD YOU EXPLAIN THE ADJUSTMENT WHICH YOU HAVE MADE TO THE PAYMENT LAGS ASSOCIATED WITH INTEREST ON LONG-TERM DEBT AND PREFERRED STOCK DIVIDENDS?

A. Yes. In its lead-lag study, PP&L assigned a payment lag of 90 days to interest on long-term debt based on the semi-annual payment of that interest and 45 days to preferred dividends based on their quarterly payment. These lags of 90 and 45 days are consistent with a 360-day year. I have revised the payment lag for interest on long-term debt to 91.25 days (91.3 rounded) and the payment lag for preferred dividends to 45.63 days (45.6 rounded) to reflect a 365-day year.

Q. HAVE YOU PREPARED A SCHEDULE SUMMARIZING YOUR CASH WORKING CAPITAL RECOMMENDATION?

A. Yes. Schedule TSC-6 summarizes my working capital calculation. In making my calculation, I have adjusted expenses and taxes to recognize the OCA's recommended adjustments to the Company's request. As shown on that schedule, I have determined PP&L's cash working capital requirement to be ($9,589,000) on a Pennsylvania jurisdictional basis. This represents an increase in jurisdictional rate base of $1,982,000.

Net Income

Q. HAVE YOU MADE A DETERMINATION OF PP&L'S TEST YEAR NET OPERATING INCOME AT PRESENT RATES?

A. Yes. As shown on Schedule TSC-7, I have determined PP&L's Pennsylvania jurisdictional net operating income at present rates to be $461,251,000. This represents an increase of $94,629,000 compared to the jurisdictional net income at present rates of $366,622,000 identified by PP&L in its initial filing. Page 1 of Schedule TSC-7 summarizes the net income effect of each of the adjustments which I have recommended that produce this increase. Page 2 of this schedule provides a breakdown of the effects of each of my adjustments according to the components of the income statement. I would note that the income amounts shown on Schedule TSC-7 do not include Mr. Kahal's excess capacity adjustment to eliminate the return on equity associated with Susquehanna Unit 2. This adjustment is recognized in the return calculations on Schedule TSC-1.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO RECOGNIZE THE BENEFIT SAVINGS ASSOCIATED WITH PP&L'S YEAR END EMPLOYEES AND WAGES?

A. PP&L adjusted its future test year expenses to reflect the projected year end level of employees and wages, as shown on Schedule D-5 of PP&L Exhibit Future 1. In developing this adjustment, the Company did not account for the reduction in benefits and payroll taxes which will accompany the reduction in employees and wages. However, in response to OCA IX-29, the Company agreed that it would be appropriate to adjust benefits and payroll taxes for the reduction in employees and wages. Accordingly, I have made this adjustment.

Schedule TSC-8 provides the calculation of the adjustment to benefits and payroll taxes to reflect year end employees and wages. To calculate this adjustment, I have utilized the 1995 ratio of benefits and payroll taxes to wages. As shown on Schedule TSC-8, this adjustment reduces test year expenses by $197,000 on a total company basis and $171,000 on a jurisdictional basis. The concomitant increases in net income are $114,000 and $99,000, respectively.

Q. HOW DID PP&L DETERMINE THE PENSION EXPENSE AND SFAS NO. 106 POSTRETIREMENT BENEFITS EXPENSE INCLUDED IN ITS TEST YEAR EXPENSE CLAIM.

A. In its filing, PP&L has based its pension expense on an actuarial estimate of the cost under SFAS No. 87. In developing its estimate of pension expense for purposes of its filing, PP&L utilized its 1994 actuarial report prepared by Towers Perrin as the starting point. It then adjusted this estimate to reflect certain plan changes and an adjustment to increase the discount rate used in the study from 7.0 percent to 7.25 percent.[2] At the time of the hearings on March 21, 1995, the Company submitted an updated Towers Perrin actuarial report for 1995 in which the discount rate was increased to 7.5 percent.

Similar to pension expense, PP&L has based its postretirement benefits expense claim on an actuarial estimate of the costs under SFAS No. 106. This estimate was prepared for 1995 in late 1994 and utilized a discount rate of 7.5 percent compared to the 7.0 percent discount rate used in the 1994 SFAS No. 106 actuarial report.

[2]The calculation of the Company's filed claim was provided in the original response to OCA IV-102. That response does not explicitly state the discount rate used. However, based on the amount of the adjustment for the discount rate increase, it appears that a .25 percent increase from 7.0 percent to 7.25 percent was reflected.

Q. PLEASE EXPLAIN WHY YOU ARE PROPOSING TO ADJUST PENSION AND POSTRETIREMENT BENEFITS EXPENSE TO REFLECT A REVISED DISCOUNT RATE.

A. At the time at which the Company's 1994 actuarial reports were prepared in early 1994, a discount rate of 7 percent was used. This discount rate was selected after considering the yields on four different types of investment grade bonds as of December 31, 1993. As shown in the following table, the yield on each type of bond had increased by approximately 1.5 percent as of December 31, 1994. This data supports an increase in the discount rate of more than the one-half of one percent (0.5 percent) recognized by PP&L. Consistent with the increase in bond yields, I am proposing to increase the discount rate by 1.5 percent.

Table A

Comparison of Bond Yields
As of December 31, 1993 and 1994[1]

	12/31/93	12/31/94	Change
30-Year Treasury Bonds	6.35%	7.89%	1.54%
Merrill Lynch 10+ High Quality Corporate Bonds	7.22%	8.60%	1.38%
Moody's BAA Corp. Bonds	7.70%	9.14%	1.44%
PBGC Immediate Annuity Rate	4.50%	6.00%	1.50%

Note:

[1] Per 1995 Retirement Plan Actuarial Report, dated February 1995, page MS-2. (Report provided in update to the response to OCA IV-101.)

Q. DO YOU HAVE INFORMATION WHICH INDICATES THAT AN INCREASE IN THE DISCOUNT RATE TO 8.5 PERCENT IS REASONABLE?

A. Yes. PP&L's actuary, Towers Perrin, also serves as the actuary for the American Water Works Company, Inc., of which Pennsylvania-American Water Company is a subsidiary. In its currently pending rate case, Pennsylvania-American recently updated its pension and postretirement benefits claims to reflect the results of the actuarial valuations for 1995. In the 1995 actuarial reports for American Water Works, Towers Perrin increased the discount rate by 1.5 percent from the 7.25 percent used in their 1994 reports to 8.75 percent for 1995.

Q. WHAT IS THE EFFECT OF INCREASING THE DISCOUNT RATE TO 8.5 PERCENT ON POSTRETIREMENT BENEFITS EXPENSE?

A. As shown on Schedule TSC-9, increasing the discount rate to 8.5 percent reduces the annual accrual for postretirement benefits expense by $700,000, of which $606,000 is allocable to the Pennsylvania jurisdiction. This adjustment results in a reduction in postretirement benefits charged to O&M of $481,000 on a total company basis and $416,000 on a jurisdictional basis. This reduction in expense has no effect on income taxes because the postretirement benefit accruals in excess of the pay-as-you go expense are not tax deductible. Therefore the increase in net income is equal to the reduction in expense on both a total company and jurisdictional basis.

Q. WHAT IS THE EFFECT OF INCREASING THE DISCOUNT RATE ON PENSION EXPENSE?

A. In its filing, PP&L claimed a pension cost of $17,898,000, of which $12,296,000 is charged to O&M expense. Based on a discount rate of 8.5 percent, I have estimated that the pension cost will be zero. Therefore, I have reduced O&M expense by $12,296,000. As shown on Schedule TSC-10, this adjustment reduces jurisdictional expenses by $10,642,000. As with the adjustment to postretirements benefits expenses, this adjustment has no effect on income taxes because the claimed SFAS No. 87 pension expense was not included as tax deductible in the Company's filing. Therefore, the net income effect of my adjustment to pension expense is equal to the reduction in expense.

Q. HOW DID YOU ESTIMATE THE REVISED PENSION COST OF ZERO?

A. Based on its updated actuarial report for 1995, PP&L has revised its estimate of pension costs downward to $11,867,000. Incorporated in this overall reduction is a reduction of over $7.5 million resulting from increasing the discount rate by 0.5 percent. Since the effect of successive increases in the discount rate will decline as the discount rate gets higher, a further increase in the discount rate of 1 percent will produce something less than a $15 million reduction in pension costs. Therefore, to be conservative, I have assumed that pension costs will fall to zero and not become negative. If the Company updates its pension actuarial study to reflect an 8.5 percent discount rate, I will consider the results of that study in developing my adjustment.

Q. PLEASE SUMMARIZE PP&L'S CLAIM FOR THE RECOVERY OF PRIOR PERIOD SFAS NO. 106 RELATED COSTS.

A. PP&L has requested that it be allowed to recover $31.1 million prior period costs related to SFAS No. 106. These expenses represent the incremental costs incurred under SFAS No. 106 from January 1, 1993, when SFAS No. 106 became effective until September 30, 1995, the end of the future test year in this case. PP&L is seeking recovery of these costs on the basis that the incremental costs of SFAS No. 106 have not previously been explicitly recognized in rates. The Company has proposed to amortize these costs over 17.3 years, which corresponds to the remainder of the transition period allowed by SFAS No. 106.

Q. ARE THESE COSTS BEING DEFERRED ON PP&L'S BOOKS?

A. No. PP&L filed a petition with the Commission requesting that it be allowed to defer its incremental SFAS No. 106 expenses as a regulatory asset in Docket No. P-00920635. On May 6, 1993, the Commission approved the Company's request and PP&L began to defer the costs beginning January 1, 1993. However, in May 1994, the Commonwealth Court of Pennsylvania reversed the Commission's approval and concluded that allowing deferral for future recovery of the incremental costs would constitute retroactive ratemaking. As a result, PP&L discontinued the deferral and wrote-off the amounts previously deferred.

Q. SHOULD THE COMPANY'S REQUEST TO RECOVER THE SFAS NO. 106 COSTS RELATED TO PRIOR PERIODS BE ALLOWED?

A. No. The fact that SFAS No. 106 had to be adopted for accounting purposes by no later than for fiscal years beginning after December 15, 1992 was known well in advance. Moreover, the expense under SFAS No. 106 represents a recurring annual expense and is neither extraordinary or non-recurring. As a result, PP&L (and other utilities) had ample opportunity to seek recognition of the expenses under SFAS No. 106 in rates prior to the final implementation date of January 1, 1993.

Since the Company could have sought timely recovery of these costs, PP&L should not be allowed to now go back and seek recovery of one selected item of expense for a historical period. Doing so would represent both single issue and retroactive ratemaking. In this regard, Counsel has advised me that based on the Commonwealth Court decision discussed previously, the recovery of prior period SFAS No. 106 expenses constitutes retroactive ratemaking and is not allowed.

Q. WHAT IS THE EFFECT OF DISALLOWING THE RECOVERY OF THE PRIOR PERIOD SFAS NO. 106 EXPENSE?

A. As shown on Schedule TSC-11, disallowing the recovery of prior period SFAS No. 106 costs reduces test year expenses by $1,797,000 on a total company basis and by $1,555,000 on a jurisdictional basis. Because the amortization of these costs was not considered tax deductible, the adjustment to eliminate prior period SFAS No. 106 costs has no effect on income taxes. Accordingly, the increase in net income resulting from this adjustment is equal to the reduction in expense.

Q. PLEASE SUMMARIZE THE COMPANY'S CLAIM FOR EXPENSES RELATED TO SFAS NO. 112.

A. PP&L has included $996,000 in the future test year for the accrual of costs under SFAS No. 112. SFAS No. 112 pertains to the long-term disability and other benefits provided to disabled employees and their spouses (post employment benefits). The $996,000 cost which PP&L has recognized represents an accrual for the projected increase in the future liability for long-term disability and survivor income protection and is in addition to the actual benefits to be paid during the future test year.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THIS CLAIM?

A. I am proposing to disallow the Company's claimed accrual for SFAS No. 112 related costs. In response to OTS-RE-105, the Company has indicated that these accruals are relatively short-term liabilities. Therefore, the Company does not intend to fund these costs in the same manner as SFAS No. 106 expenses but instead intends to pay for the costs as they become due. Test year expenses already include the annual cost associated with the post-employment benefits which are being paid. Ratepayers should not also be required to pay for future liabilities which PP&L itself does not intend to pay until they become due.

The calculation of my adjustment to disallow SFAS No. 112 accruals is shown on Schedule TSC-12. As indicated there, this adjustment reduces test year O&M expense by $684,000 on a total company basis and by $592,000 on a Pennsylvania jurisdictional basis. Eliminating this expense has no income tax effects because SFAS No. 112 accruals are not tax deductible and were not recognized as tax deductible by PP&L. Therefore, the increase in net income resulting from this adjustment is equal to the reduction in expense.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INTEREST ON CUSTOMER DEPOSITS.

A. Pursuant to changes to 52 Pa. Code §56.57 effective on April 14, 1995, the legal rate of interest to be paid on customer deposits is now equal to the average interest rate on one year treasury bills for September, October and November of the previous year. PP&L has indicated that it will propose to modify its tariff in this proceeding to reflect this new legal interest rate. This will result in the current 11 percent interest rate being reduced to 5.77 percent for 1995. Accordingly, I have adjusted the expense for interest on customer deposits to recognize this change. This results in a reduction in total Company and jurisdictional expense of $58,000 and an increase in net income of $34,000, as shown on Schedule TSC-13.

Q. PLEASE SUMMARIZE PP&L'S CLAIM FOR NUCLEAR DECOMMISSIONING FUNDING IN THIS PROCEEDING.

A. PP&L is requesting an allowance of $30,042,000 per year to fund the decommissioning of Susquehanna Units 1 and 2. This total consists of $12,609,000 for Susquehanna Unit 1 and $17,433,000 for Susquehanna Unit 2. These figures compare to current funding provisions of $3,803,000 per year for Unit 1 and $3,291,000 per year for Unit 2.

PP&L's decommissioning funding claim is based on estimated decommissioning costs, in 1993 dollars, of $315,471,000 for its 90 percent share of Unit 1 and

$408,361,000 for its 90 percent share of Unit 2. The Company has assumed that these costs will increase at a rate of inflation of 4 percent per year. The Company has assumed that earnings on the trust fund balances will equal 5.8 percent per year less 0.3 percent per year for fees and expenses for a net return of 5.5 percent per year.

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE CALCULATION OF THE FUNDING REQUIREMENT BASED ON THE COMPANY'S CLAIMED DECOMMISSIONING EXPENSE?

A. I have identified two adjustments which affect the decommissioning funding requirement in this proceeding. First, I have modified the calculation of the required annual contributions to the fund to recognize that the trust fund will continue to earn a return during the decommissioning period. Second, I have reflected an increase in the projected rate of return which PP&L can expect to receive on funds invested in the decommissioning trust.

Q. WHAT MODIFICATION ARE YOU PROPOSING TO THE MANNER IN WHICH THE ANNUAL CONTRIBUTIONS TO THE DECOMMISSIONING FUND WERE ESTABLISHED BY PP&L IN ITS FILING?

A. To calculate the annual contribution required to fund the decommissioning of Susquehanna Units 1 and 2, PP&L assumed that the full amount of the funds required would have to be available at the time each unit is retired. This procedure fails to recognize that the decommissioning process and the associated expenditures will take place over 12 years for Unit 1 and 10 years for Unit 2. As a result, monies will remain in the decommissioning trust funds and those funds will continue to realize significant earnings during the period over which the decommissioning activities take place once the units are retired.

In order to recognize the fund earnings during the period over which decommissioning takes place, I have utilized a decommissioning model which takes into consideration the timing of the decommissioning expenditures. In developing this model, I have recognized that inflation will continue to affect decommissioning costs over the 10 and 12 year periods during which decommissioning of the units will take place and that, in turn, this will affect the total decommissioning funds which are required. I have also recognized that the unexpended balances of the trust funds will earn a return during those time periods.

Q. HAS THIS METHOD FOR DETERMINING FUNDING REQUIREMENTS BEEN UTILIZED BY OTHER COMMISSIONS AND UTILITIES?

A. Yes. The Federal Energy Regulatory Commission utilizes the procedure which I am recommending in establishing the decommissioning funding requirements for nuclear units subject to its jurisdiction. In addition, in the previous rate cases in which I have been involved where decommissioning funding requirements for nuclear units were established, the utility itself has proposed to establish funding contributions taking into consideration interest earned during the decommissioning period. These cases have involved Louisiana Power & Light Company, System Energy Resources, Inc. and Commonwealth Edison Company, which has 16 nuclear units and is the largest investor-owned nuclear utility in the U.S.A.

Q. WHAT IS THE EFFECT OF PROPERLY RECOGNIZING THE FUND EARNINGS DURING THE DECOMMISSIONING PERIOD?

A. Simply recognizing that the decommissioning trust funds will continue to earn a return after the units are retired without recognizing any other changes results in funding requirements of $11,399,000 per year for Unit 1 and $15,538,000 for Unit 2. This represents a reduction of over $3.1 million per year compared to PP&L's claim.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE RATE OF RETURN EXPECTED TO BE EARNED ON THE FUNDS INVESTED BY THE DECOMMISSIONING TRUST?

A. A key element in determining the contributions which must be collected from ratepayers to fund decommissioning costs is the estimate of what the funds invested in the decommissioning trust will earn once they have been collected. To develop its estimate of the returns which the decommissioning funds will earn, PP&L established an investment strategy and projected the rates of return which the various types of investments (e.g., stocks, bonds, treasuries, etc.) will earn. My associate, Mr. Kahal, has reviewed those projections and has identified several changes which must be made to avoid understating fund earnings. As shown on Schedule MIK-10, those revisions result in an increase in the average trust fund after-tax rate of return from the 5.8 percent projected by PP&L to 7.5 percent.

Q. HAVE YOU DEVELOPED A SCHEDULE OF DECOMMISSIONING PAYMENTS WHICH REFLECTS THE CHANGES WHICH YOU HAVE PROPOSED TO THE CALCULATION OF THE FUNDING REQUIREMENTS?

A. Yes. Pages 2 and 3 of Schedule TSC-14 present the schedules of decommissioning payments which I am recommending for Susquehanna Units 1 and 2, respectively. In developing these schedules, I have utilized the model discussed previously which takes into account the timing of the decommissioning expenditures. I have also reflected Mr. Kahal's recommendation regarding the appropriate fund earnings rate. In developing my estimate of the amount of the required ratepayer contributions to the decommissioning trust, I have adjusted Mr. Kahal's recommended annual rate of return of 7.5 percent on the trust assets to reflect the expense ratio of 0.3 percent identified by PP&L. This results in a net trust fund rate of return of 7.2 percent.

Page 1 of Schedule TSC-14 summarizes the annual nuclear decommissioning contributions which I have developed for Susquehanna Units 1 and 2. As shown there, the annual fund contributions which I have identified are $6,238,000 for Unit 1 and $9,028,000 for Unit 2. This results in a total annual decommissioning funding expense of $15,266,000, of which $11,977,000 is allocable to the Pennsylvania jurisdiction. Compared to the Company's claim, this represents a reduction of $14,776,000 on a total company basis and $11,593,000 on a jurisdictional basis.

In calculating the income tax effect of this adjustment, I have recognized that only 97.5 percent of the decommissioning contribution for Susquehanna Unit 1 is tax deductible. This is due to the fact that the unit began commercial operation prior to 1984 which is the first year the IRS allowed tax deductions for funding decommissioning. As shown on Schedule TSC-14, the increase in net income resulting from my adjustment to decommissioning expense is $9,040,000 on a total company basis and $7,093,000 on a Pennsylvania jurisdictional basis.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO DECOMMISSIONING FUNDING REQUIREMENTS RELATED TO CHANGES TO THE COSTS OF DECOMMISSIONING SUSQUEHANNA UNITS 1 AND 2?

A. In developing the decommissioning contributions discussed previously and shown on Schedule TSC-14, I have utilized PP&L's claimed costs for decommissioning Susquehanna Units 1 and 2. OCA witness Dale Bridenbaugh has recommended that PP&L's claimed decommissioning costs be adjusted to exclude the non-radiological costs and the contingencies incorporated in the estimates. Therefore, I have calculated adjusted funding contributions which reflect these changes. As shown on Schedule TSC-15, excluding non-radiological costs and contingencies from the costs to be funded reduces the required annual contributions by $6,402,000 on a total company basis and $5,022,000 on a Pennsylvania jurisdictional basis. This results in increases of $3,733,000 in total company net income and $2,928,000 in jurisdictional net income.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL WITH REGARD TO DECOMMISSIONING EXPENSE FOR ITS FOSSIL FUELED GENERATING UNITS.

A. PP&L has proposed to adjust test year expenses to include an allowance for the decommissioning of its fossil fueled generating stations at Martins Creek, Brunner Island, Montour, Sunbury and Holtwood. This decommissioning accrual is intended to recover the future expected cost of decommissioning each unit over the current scheduled remaining life of that unit. In the case of Martins Creek Units 1 and 2, Sunbury and Holtwood Unit 17, the Company has utilized the early deactivation dates which it has proposed in this case. PP&L calculated the amount of its claimed decommissioning accruals using the same annuity calculations which it used for nuclear decommissioning expense. As with nuclear decommissioning costs, PP&L assumed that the current costs would be subject to 4 percent per year inflation and that the funds collected would earn a return of 5.5 percent per year.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO PP&L'S CLAIMED DECOMMISSIONING EXPENSE FOR ITS FOSSIL FUELED GENERATING STATIONS?

A. I am proposing to adjust test year expenses to eliminate the decommissioning annuity which PP&L has included for its fossil fueled generating stations. This decommissioning accrual is based on the assumption that each of the units will be retired and decommissioned at the end of their currently scheduled lives or, in some instances, even earlier. However, it is common for electric utilities to undertake plant life extensions in which the generating facility is overhauled and the life extended. In fact, in its most recent "Five Year Upgrade Plan for Coal Fired Generation," dated May 2, 1994, PP&L concluded that it would be prudent to undertake the investments necessary to continue operation of each of its fossil fueled generating units for at least another 20 years. Moreover, in response to OCA IX-24, the Company has stated that it will continue to consider life extensions at its fossil fueled generating stations in the future. Therefore, it would be premature to include a decommissioning allowance for fossil fueled generating facilities in rates at the present time.

Q. IS THERE ANY REQUIREMENT THAT PP&L ESTABLISH DECOMMISSIONING FUNDS FOR ITS NON-NUCLEAR GENERATING FACILITIES?

A. No. The only requirements which exist for funding decommissioning costs pertain to nuclear units. There are no requirements that apply to the funding of the decommissioning of fossil fueled generating facilities.

Q. HOW SHOULD THE COSTS OF DECOMMISSIONING PP&L'S NON-NUCLEAR UNITS BE RECOVERED?

A. Counsel advises me that the <u>Penn Sheraton</u> decision provides for the recovery of net negative salvage costs when an asset is retired. Net salvage is defined in the FERC Uniform System of Accounts as "the salvage value of property retired less the cost of removal." Net negative salvage simply means that the costs of removal exceed the salvage value. Accordingly, the decommissioning of the Company's fossil fueled generating stations represents the net cost of removing those assets and will be properly recognized as net negative salvage after retirement occurs. To accomplish this, Pennsylvania has used a five-year rolling average allowance for net salvage.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT ON THE COMPANY'S CLAIMED COST OF SERVICE?

A. As shown on Schedule TSC-16, eliminating the annual accrual for the decommissioning of the Company's fossil fueled generating units reduces total company expenses by $52,818,000 and Pennsylvania jurisdictional expenses by $43,041,000. This results in an increase in net income of $30,558,000 on a total company basis and $24,902,000 on a jurisdictional basis.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY'S CLAIMED ACCRUALS FOR DECOMMISSIONING ITS FOSSIL FUELED UNITS?

A. Yes. As noted previously, the Company's calculations of the decommissioning accrual for its fossil fueled units are directly comparable to those for its nuclear units. Accordingly, the Company's claim overstates the appropriate decommissioning expense. If the Commission does allow a decommissioning accrual for the fossil units, the Company's accruals should be adjusted to account for fund earnings during the decommissioning period and recognize a net fund earnings at a rate of 7.2 percent rather than 5.5 percent.

Q. PLEASE SUMMARIZE PP&L'S REQUEST FOR THE RECOVERY OF SUSQUEHANNA EARLY WINDOW DEFERRALS.

A. PP&L is proposing that it be allowed to recover the costs which it deferred between the time Susquehanna Units 1 and 2 were placed into commercial operation and the time the costs of the units were recognized in rates. The costs for Unit 1 were deferred from June 8, 1983 to August 22, 1983 when the rates approved in Docket No. R-822169 went into effect. The costs for Unit 2 were deferred from February 12, 1985 until April 26, 1985 when rates were approved in Docket No. R-842651. The deferred costs for which PP&L is seeking recovery consist of $39,194,000 of operating expenses, plus $60,959,000 of deferred carrying costs, less $88,161,000 of interchange energy savings, for a net balance of $11,992,000. PP&L is proposing to amortize these costs over 10 years.

Q. HAS RECOVERY OF THESE DEFERRED COSTS BEEN PREVIOUSLY APPROVED BY THE COMMISSION?

A. No. The deferrals of the early window costs for Susquehanna Units 1 and 2 were approved by the Commission in Docket Nos. P-820367 and P-842651, respectively. However, in its Order in each of those cases, the Commission stated that the issuance of the Order was not a determination by the Commission that the Company may recover the deferred costs or retain the deferred energy savings: In its Order in Docket No. P-820367 entered July 29, 1992, the Commission also stated that: "The burden to show the justness and reasonableness of any proposed rate change including recovery of deferred costs shall remain squarely with PP&L." (Order at page 5.)

Q. WHY ARE YOU PROPOSING TO DISALLOW THE RECOVERY OF THE EARLY WINDOW DEFERRALS?

A. I am proposing to disallow recovery of the Susquehanna early window deferrals because recovery of those costs is no longer timely. It has been more than 10 years since the last of the early window deferrals occurred and since PP&L last filed a rate case. During that time period, PP&L voluntarily elected not to file for rate relief, presumably because it believed its earnings were at or above what the Commission would deem to be a reasonable level. Unless PP&L can establish that it was not earning a reasonable return and would not have earned a reasonable return had it amortized the early window costs during the last ten years, it should not now be allowed to recover the early window deferrals.

Q. IN HIS TESTIMONY, MR. BERNINI CLAIMS THAT RECOVERY OF THE EARLY WINDOW COSTS IS CONSISTENT WITH THE COMMISSION'S

MAY 16, 1990 ORDER IN PHILADELPHIA ELECTRIC COMPANY'S (PECO'S) RATE CASE IN DOCKET NO. R-891364. DO YOU HAVE ANY COMMENTS?

A. Yes. While the Commission did allow PECO to recover the early window deferrals associated with Limerick Unit 1 in that case, there are several important distinctions between the circumstances in that case and this one. First, PECO was seeking recovery of deferrals which took place in 1986 through a rate case filed in 1989. PP&L is seeking recovery in a case filed 11½ years after the Susquehanna Unit 1 deferrals and 9½ years after the Unit 2 deferrals. Second, PECO sought recovery of the Limerick deferrals in its next base rate case. For the Susquehanna Unit 1 deferrals for which PP&L is now seeking recovery, this is not the first rate case after that in which the unit was reflected in rates. Finally, the Order in Docket R-891364 emphasized the Commission's concern about the serious impact on PECO's financial condition if it was forced to write-off its Limerick deferrals which totalled over $240 million for Limerick Units 1 and 2. The write-off of $12 million of Susquehanna early window write-off, while not trivial, would not have a serious impact on PP&L's financial condition.

Q. WHAT IS THE EFFECT OF ELIMINATING THE AMORTIZATION OF THE EARLY WINDOW DEFERRALS?

A. As shown on Schedule TSC-17, disallowing the amortization of the Susquehanna early window deferrals reduces test year expenses by $1,199,000. Since the amortization of the early window deferrals was not recognized as tax deductible by PP&L, this adjustment does not result in an increase on income taxes. Therefore, the net income effect of eliminating the amortization is also $1,199,000. The entire amount of this adjustment is allocable to the Pennsylvania jurisdiction.

I would note that if the Commission does allow the recovery of the early window deferrals, the amortization should be treated as tax deductible for ratemaking purposes. PP&L received a tax deduction for the deferred costs at the time they were incurred. Therefore, the Company should be required to pass the resulting tax benefits through to ratepayers if it is allowed to recover the costs.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON THE AMORTIZATION OF SUSQUEHANNA REFUELING OUTAGE COSTS.

A. PP&L normalizes refueling outage costs by amortizing the costs of the outage over the period between refueling outages, which is typically around 18 months. PP&L's future test year expenses reflect the completion of the amortization of reload outage 7 and the initiation of reload outage 8 at Susquehanna Unit 1 and the amortization of reload outage 6 at Unit 2.

I am proposing to adjust the amortization of refueling outage costs to reflect the annualized level of costs based on the level of amortization associated with the most recent outage for each unit as of the end of the test period. I have based this on the costs of reload 8 at Susquehanna Unit 1, which is scheduled to take place from March 25 through May 22, 1995, and reload 7 at Unit 2, which is scheduled to take place from September 16 to November 13, 1995. As shown on Schedule TSC-18, this adjustment reduces total company expenses by $1,416,000 and jurisdictional expenses by $1,111,000. The resulting increases in net income are $819,000 and $643,000, respectively.

Q. OTHER THAN RELOAD 7 BEING THE MOST RECENT REFUELING OUTAGE AT SUSQUEHANNA UNIT 2 AS OF THE END OF THE TEST YEAR, IS THERE ANOTHER REASON WHY YOU ARE PROPOSING TO

BASE THE ANNUALIZED REFUELING OUTAGE COSTS FOR UNIT 2 ON RELOAD 7 RATHER THAN RELOAD 6?

A. Yes. PP&L experienced problems during reload 6 at Susquehanna Unit 2. Because of these problems, the costs associated with reload outage 6 at Unit 2 were higher than normal. In addition, the duration of this outage was almost a month longer than normal. This, in turn, shortened the period over which the outage costs had to be amortized, thereby further increasing the annual amortization expense. As a result, the annual amortization expense associated with reload 6 at Susquehanna 2 is unusually high. Utilizing the annual amortization of the projected costs of reload outage 7 provides a more normal level of refueling outage expense.

Q. WHY ARE YOU PROPOSING TO ADJUST PP&L'S CLAIMED ENVIRONMENTAL REMEDIATION EXPENSES?

A. PP&L has included a provision of $450,000 per month or $5.4 million per year in test year expenses for environmental remediation costs. I am proposing to reduce this allowance for environmental remediation costs because the level of expenditures claimed by the Company is not in line with actual experience. During the historic test year, PP&L spent a total of $1,451,000 for an average of $121,000 per month on environmental remediation costs. During the first five months of the future test year, the total expenditures were only $647,000 for an average of $129,000 per month. Moreover, the largest expenditure in any month during the future test year has been only $218,000 and the largest expenditure in any month was $316,000 in May 1994. This experience clearly does not support a level of expense of $450,000 per month.

Q. WHAT LEVEL OF ENVIRONMENTAL REMEDIATION EXPENSES ARE YOU PROPOSING TO RECOGNIZE?

A. I am proposing to adjust test year expenses to reflect a level of environmental remediation costs equal to the expenditures for the 12 months ended February 1995, which is the most recent data available. This results in an allowance for environmental remediation costs of $1,697,000 per year or $141,000 per month. As shown on Schedule TSC-19, this results in a reduction in expense of $3,703,000 on a total company basis and $3,017,000 on a Pennsylvania jurisdictional basis. The concomitant increases in net income are $2,142,000 and $1,745,00, respectively.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. I have adjusted depreciation expense to reflect the changes to the Company's claim presented by Dr. Charles Johnson on behalf of the OCA. As shown on Schedule TSC-20, Dr. Johnson's recommendations reduce depreciation expense by $51,028,000 on a total company basis and $40,855,000 on a jurisdictional basis. The resulting increases in net income are $33,168,000 and $26,556,000. In calculating the net income effects, I have recognized that the change in book depreciation will have no effect on tax depreciation and, hence, no effect on current income taxes. Instead, the reduction in book depreciation increases the difference between book and tax depreciation and, as a result, increases deferred federal income taxes.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EDI/IDI CREDITS?

A. In his testimony, Dr. Johnson has recommended that one-half of the revenue foregone as the result of EDI/IDI rates be absorbed by the Company and one-half be borne by ratepayers. Therefore, I have adjusted revenues at present rates to reflect one-half of the EDI/IDI revenue foregone. As shown on Schedule TSC-21, this adjustment increases revenue by $12,666,000 and net income by $7,006,000.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO GROSS RECEIPTS TAXES?

A. PP&L calculated gross receipts tax expenses by applying the current gross receipts tax rate to its projected test year revenues from electric sales (excluding certain wholesale and contract sales) and late payment charges. This calculation fails to recognize that revenues which are not received (i.e., uncollectibles) are not subject to gross receipts tax. Therefore, as shown on Schedule TSC-22, I have revised the calculation of gross receipts taxes to exclude uncollectibles revenues. This adjustment reduces the taxable revenue base by $16,932,000 on both a total company and Pennsylvania jurisdictional basis. Applying the current gross receipts tax rate to this amount reduces gross receipts tax by $745,000 and increases net income by $431,000.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INCOME TAXES FOR THE ELIMINATION OF CERTAIN ADDITIONS TO TAXABLE INCOME.

A. I have eliminated three items which the Company included as additions to taxable income for purposes of calculating future test year income tax expense. First, I have eliminated the addition to taxable income for an ECR/FAC overrecovery of $9,690,000. This addition represents the amount by which fuel revenues are expected to exceed actual cash expenditures for fuel-related costs during the future test year. This overrecovery is caused by fluctuations in fuel revenues and fuel costs in combination with the fact that underrecoveries in one year are made up by recoveries in the following year (and vice versa). This is borne out by the fact that, in the historical test year, there was an ECR/FAC underrecovery of $20,522,000 which was deducted from taxable income. Therefore, ECR/FAC over or underrecoveries represent a short-term, temporary timing difference and should not be included in the calculation of income taxes used to set rates.

The second adjustment to taxable income which I have eliminated is an addition of $2,724,000 for refueling costs. This item represents the difference between the

Susquehanna refueling outage costs which are reflected as a test year expense and the refueling outage costs which are deductible for income tax purposes. This difference is caused by the fact that refueling outage costs are normalized over the approximately 18-month period between refueling outages for accounting and ratemaking purpose whereas, for income tax purposes, the costs are deducted when incurred. Depending on the timing of the outage, the difference between normalized outage costs and tax deductible outage costs can vary significantly from year-to-year. For example, in the historical test year, this difference resulted in deduction from taxable income of $10,125,000 compared to the future test year addition of $2,724,000. However, over the 18-month period of the refueling cycle, the refueling outage costs for accounting and ratemaking are equal to those tax purposes. Therefore, like ECR/FAC over and underrecoveries, refueling outage costs represent a short-term, temporary timing difference which should not be included in the calculation of the income taxes used to set rates.

The third item which I am proposing to eliminate from the calculation of test year income taxes is the addition to taxable income for the excess of test year uncollectibles expense over projected bad debt write-offs. I have accepted the Company's projected test year uncollectibles expense as representative of actual bad debt write-offs. To the extent the uncollectibles expense included in rates exceeds actual bad debt cost, either uncollectibles expense should be reduced or the uncollectibles reserve, which represents the excess of uncollectible expense over actual write-offs, should be deducted from rate base as a source of ratepayer supplied funds. Otherwise, ratepayers should receive a tax deduction for the full amount of the expense they pay.

Q. WHAT IS THE EFFECT OF THESE ADJUSTMENTS ON TEST YEAR INCOME TAX EXPENSE?

A. As shown on Schedule TSC-23, eliminating the additions to taxable income for ECR/FAC overrecoveries, refueling outage costs and bad debt accruals reduces income taxes and increases net income by $6,058,000 on a total company basis. On a Pennsylvania jurisdictional basis, the reduction in income taxes and increase in net income is $5,810,000.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATED TO ACCRUALS FOR INCOME TAX DEFICIENCIES.

A. PP&L adjusted its calculated test year income tax expense to include accruals of $252,000 for a potential state income tax deficiency and $948,000 for a potential federal income tax deficiency. I have adjusted test year income tax expense to eliminate these accruals. As shown on Schedule TSC-24, this adjustment reduces income taxes and increases net income by $1,200,000 on a total company basis and by $1,017,000 on a jurisdictional basis.

Q. WHAT IS THE BASIS FOR YOUR ADJUSTMENT?

A. According to the response to OCA IV-120, "[t]he accruals for potential deficiencies in state and Federal income taxes are non-specific estimates of possible additional assessments arising out of Federal and state tax audits." The response goes on to indicate that "[t]he estimates are based on general approximation of audit adjustments..." As such, the Company's accruals for potential tax deficiencies do not represent a known and measurable cost. Moreover, since the accruals are based on non-specific estimates, there is no evidence or documentation to support any claim that any of the potential deficiencies are as the result of any tax benefits which were passed through to ratepayers. Therefore, these accruals are not properly reflected in rates.

Q. PLEASE SUMMARIZE THE RATIONALE FOR MAKING A CONSOLIDATED TAX SAVINGS ADJUSTMENT.

A. PP&L participates in the consolidated federal income tax return filed by the Company and its subsidiaries (the PP&L System). The filing of a consolidated income tax return results in utility corporations such as the PP&L System paying less income taxes in a given year than would be paid if each subsidiary filed a separate income tax return. This difference or consolidated tax savings results from the ability to take advantage of the losses of the parent and the unregulated subsidiaries on a consolidated basis by utilizing the income of the regulated utility (or utilities) to offset those losses.

Q. WHAT HAS BEEN THE MAIN ARGUMENT AGAINST RECOGNIZING CONSOLIDATED TAX SAVINGS IN SETTING A UTILITY'S RATES?

A. One of the primary arguments against recognizing a utility's share of the savings realized by filing a consolidated tax return has been that doing so would violate the normalization provisions of the Internal Revenue Code.

Q. HAVE ANY DEVELOPMENTS TAKEN PLACE WHICH HAVE A BEARING ON THE ISSUE OF RECOGNIZING A CONSOLIDATED TAX SAVINGS ADJUSTMENT?

A. Yes. In late 1990, the U.S. Internal Revenue Service (IRS) issued proposed regulations pertaining to the ratemaking treatment of a utility's share of the savings attributable to participation in a consolidated tax return. Those proposed regulations, if they had been adopted, would have required that, in order to comply with the normalization provisions of the IRC, a utility's tax expense must be calculated without recognizing a consolidated tax savings adjustment. The proposed regulations would have allowed the recognition of a utility's share of the consolidated tax savings as a source of zero cost capital in the form of a deduction from rate base. However, even that rate base deduction would have been limited to consolidated tax savings realized after the proposed rule became final.

Q. WHAT IS THE STATUS OF THOSE PROPOSED REGULATIONS?

A. In April 1991, after receiving comments from regulators, consumer advocates, and the utility industry and its representatives, the IRS withdrew its proposed regulations. Subsequently, in a prepared statement presented to the Congressional Subcommittee on Select Revenue Measures on September 11, 1991, Deputy Assistant Secretary of Treasury Michael J. Graetz indicated that recognizing consolidated tax savings does not violate the normalization requirements of the IRC.

Q. PLEASE EXPLAIN HOW YOU ARE PROPOSING TO DETERMINE THE COMPANY'S SHARE OF THE SAVINGS REALIZED BY THE PP&L SYSTEM AS THE RESULT OF FILING A CONSOLIDATED TAX RETURN.

A. I am proposing that the consolidated tax savings allocable to the Company be determined utilizing what has become known as the modified effective tax rate method. Under this method, the first step is to determine the consolidated tax savings which result from the losses of the unregulated loss subsidiaries. These savings represent the difference between the aggregate taxes which the members of the PP&L System would have paid on separate returns compared to the taxes paid on a consolidated basis. The second step is to determine PP&L's share of the savings based on its taxable income compared to the taxable income of all members of the PP&L System with positive taxable income.

The calculation of my consolidated tax savings adjustment is presented on Schedule TSC-25. I am proposing to utilize the average consolidated tax savings for a three-year period in order to normalize the results and smooth out any fluctuations from year to year. The three years I have utilized for my calculation are the years ended December 31, 1993 and 1994 and the test year ended September 30, 1995. In developing my adjustment, I have excluded the taxable income of Interstate Energy

Corporation (IEC) because IEC's net income fluctuates between gains and losses and because IEC is operated on a non-profit basis with the objective of having no return or profit. In addition, Pennsylvania Mines Corporation (PMC) had a tax loss of $21,616,200 in 1993 due to mine closing costs. I have treated this loss as abnormal and have utilized a normalized loss for PMC in 1993 equal to the average for 1994 and 1995. As shown on Schedule TSC-25, this adjustment reduces federal income tax expense by $2,548,000 on a total company basis and $2,161,000 on a Pennsylvania jurisdictional basis.

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax deductible interest for ratemaking, I have multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended by Mr. Kahal. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown on Schedule TSC-26, this adjustment reduces the interest deduction by $475,000 compared to the interest deduction recognized by PP&L. This increases state and federal income taxes by $52,000 and $148,000, respectively.

Q. HAVE YOU PREPARED A SUMMARY SHOWING THE DETERMINATION OF STATE AND FEDERAL INCOME TAXES?

A. Yes. TSC-27 presents a proof of current taxes. I have followed the same format utilized by the Company, beginning with operating income before taxes and adjusting for the additions and deductions necessary to arrive at taxable income. As shown on Schedule TSC-27, I have started with the Company's tax calculation and identified the effects of the adjustments which I have recommended to arrive at the income tax expense consistent with income at present and proposed rates.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING PP&L'S CLAIMED TEST YEAR EXPENSES.

A. Yes. PP&L is proposing to initiate eight new customer and community needs programs or "social programs." The Company has projected that the total cost of these programs will run $6,700,000 per year. Of this total, PP&L has included $3,530,000 in test year expenses as representative of the portion of the costs which provide ratepayer benefits.

Based on the descriptions of the programs provided by PP&L, it appears that these social programs will provide some customer benefits in terms of energy efficiency, load management and conservation. However, I am concerned about the reasonableness of the costs claimed in rates for several reasons. First, the Company has provided no basis or support for either the total program costs or the portion of those costs which provide ratepayer benefits. Second, the Company has not presented an implementation plan or other details of the programs. Finally, it appears that many of the programs will not be fully implemented until after the test year so that the costs of the program will not be incurred in the test year.

Q. ARE YOU PROPOSING AN ADJUSTMENT TO THE COSTS OF THESE PROGRAMS?

A. I am not proposing an adjustment to the Company's claimed social program costs at the present time. However, the OCA reserves its right to propose an adjustment at a later stage of this proceeding if PP&L does not provide additional evidence supporting the costs of the programs which it believes should be recovered from ratepayers and demonstrating the commitment to actually spending these costs on energy efficiency, load management and conservation measures.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 1995

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Operating Income
Test Year Ending September 30, 1995
($000)

	Pennsylvania Jurisdictional Revenues At Present Rates	OCA Adjustments	Adjusted Per OCA	Proforma Increase	Proforma
Operating Revenues	$2,402,255	$12,666	$2,414,921	($73,121)	$2,341,800
Operating Expenses					
Operation & Maintenance	1,372,927	(78,417)	1,294,510	0	1,294,510
Depreciation	320,797	(40,855)	279,942	0	279,942
Regulatory Debits and Credits	(29,208)	0	(29,208)	0	(29,208)
Taxes Other Than Income	186,553	(188)	186,365	(3,729)	182,636
Federal Income Tax	154,601	16,532	171,133	(21,618)	149,515
State Income Tax	54,478	6,666	61,144	(7,626)	53,518
Deferred Income Tax	(15,424)	14,299	(1,125)	0	(1,125)
Investment Tax Credit	(8,625)	0	(8,625)	0	(8,625)
Total Taxes	371,583	37,309	408,892	(32,973)	375,919
Gain From Disposition of Emission Allowances	(466)	0	(466)	0	(466)
Total Operating Expenses	$2,035,633	($81,963)	$1,953,670	($32,973)	$1,920,697
Net Utility Operating Income	$366,622	$94,629	$461,251	($40,148)	$421,103
Rate Base	$5,017,178		$4,896,679		$4,896,679
Rate of Return	7.31%		9.42%		8.60%

PENNSYLVANIA POWER & LIGHT COMPANY

Determination of Revenue Decrease
Test Year Ending September 30, 1995
($000)

		Amount	Source
OCA Recommended Rate Base		$4,896,679	Schedule TSC-2, Page 1
Required Rate of Return		9.33%	Schedule MIK-1, Page 1
Net Operating Income Required		$456,860	
Less: Excess Capacity Adjustment		(35,757)	Schedule MIK-13
Adjusted Net Operating Income Required		421,103	
Net Operating Income at Present Rates		461,251	Schedule TSC-1, Page 1
Income Surplus		($40,148)	
Revenue Multiplier		1.8213	
Revenue Decrease Required		($73,121)	
Revenue Decrease Required		($73,121)	
PA Gross Receipts Tax	4.40%	(3,217)	
PA Capital Stock Tax	0.70%	(512)	
Subtotal		($69,392)	
State Income Tax at	10.99%	(7,626)	
Subtotal		($61,766)	
Federal Income Tax at	35.00%	(21,618)	
Net Income Decrease Required		($40,148)	

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Rate Base Adjustments
Test Year Ending September 30, 1995
($000)

	Amount	Source
Rate Base per Company Filing	$5,017,178	Schedule TSC - 2, Page 1
OCA Adjustments:		
Accrued Pensions	(74,034)	Schedule TSC - 3
Accumulated Deferred Income Taxes Associated With Loss On Required Debt	(40,838)	Schedule TSC - 4
Prepayments	(7,609)	Schedule TSC - 5
Cash Working Capital Study	1,982	Schedule TSC - 6
Total OCA Adjustments	($120,499)	
OCA Adjusted Rate Base	$4,896,679	

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Rate Base
Test Year Ending September 30, 1995
($000)

	Per Company	OCA Adjustments	Adjusted Per OCA
Utility Plant In Service			
Electric Plant in Service	$8,196,706	$0	$8,196,706
Accumulated Depreciation	(2,477,122)	0	(2,477,122)
Net Electric Plant in Service	5,719,584	0	5,719,584
Pollution Control Projects (Net of Retirements)	12,378	0	12,378
Total Utility Plant In Service	5,731,962	0	5,731,962
Working Capital			
Cash Working Capital	*(530)*	*(5,627)*	*(6,157)*
Fuel Stock And Materials & Supplies	188,808	0	188,808
Total Working Capital	188,278	(5,627)	182,651
Accumulated Deferred Income Taxes	(901,916)	(6,785)	(908,701)
Customer Advances For Construction	(40)	0	(40)
Customer Deposits	(1,106)	0	(1,106)
Accrued Pensions	0	(108,087)	(108,087)
Total Rate Base	$5,017,178	($120,499)	$4,896,679

Docket No. R-00943271
Schedule TSC-3

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Recognize
Accrued Pensions as a Rate Base Deduction
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Balance of Accrued Pensions as of 9/30/94 (2)	$104,401	$ 90,361
VERP Amortization for Test Year (3)	11,080	9,590
Pension Accrual for Test Year (4)	0	0
Projected Balance at 9/30/95	$115,481	$99,951
Deferred Taxes on Accrued Pension Balance as of 9/30/94 (2)	$(39,344)	(34,053)
Accrual Related to VERP Amortization (5)	(4,742)	(4,104)
Amount related to Pension Cost Capitalized as of 9/30/95 (2)	14,142	12,240
Projected Balance at 9/30/95	$(29,944)	$(25,917)
Net Rate Base Deduction	$ 85,537	$ 74,034

Notes:

(1) Reflects factor of 86.5518% applicable to pension expense per response to OTS-RE-3D.

(2) Per response to OCA IV-129, revised 3/27/95.

(3) Reflects 5 year amortization of final VERP pension supplement per response to OCA IV-75.

(4) Reflects OCA recommendation per Schedule TSC-10.

(5) Represents one-fifth of amount for VERP per response of OCA IV-129 (Revised 3/27/95).

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Recognize
Accumulated Deferred Income Taxes Associated
with the Loss on Reacquired Debt
Test Year Ending September 30, 1995
($000)

ADIT Associated with Loss on Reacquired Debt at 9/30/95 (1)	$47,863
Percent Allocable to Pennsylvania (2)	85.323%
Deduction from Jurisdictional Rate Base	$40,838

Notes:

(1) Per response to OCA IX-8.

(2) Based on total rate base before OCA adjustment to cash working capital and this adjustment.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Prepayments
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional
Eliminate Prepaid Insurance		
Nuclear (1)	$(2,264)	$(1,776)
Other (1)	(3,283)	(2,767)
Total	$(5,547)	$(4,543)
Revise PUC Annual Assessment		
Corrected Average Balance (2)	1,782	1,782
Amount per Company Filing (1)	379	379
Adjustment	$1,403	$1,403
Adjustment Other Prepayments to Remove		
Interest & Preferred Dividends included in March Balance (3)	$(5,164)	(4,469)
Total Adjustments to Prepayments	$(9,308)	$(7,609)

Notes:

(1) Per Schedule C-4, page 3 of Exhibit Future-1.

(2) Per response to OTS-RE-28D

(3) Reflects March balance of $67,130 per response to OTS-RE-21D divided by 13 months.

Docket No. R-00943271
Schedule TSC-6

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Cash Working Capital
Test Year Ending September 30, 1995
($000)

	Pennsylvania Adjusted Jurisdictional Amount		OCA Adjustments	OCA Adjusted Expenses	Average Daily Amount	(Lead)/Lag Days	Net (Lead)/Lag Days (Ratio)	Cash Working Capital Requirement
Operation & Maintenance Expense	$1,355,995	1/	($78,417)	$1,277,578	$3,500	31.5	3.5	$12,250
Interest on Long-term Debt	186,059	2/	(475)	185,584	$508	91.3	(56.3)	(28,600)
Preferred Dividends	27,837	2/	(1,395)	26,442	$72	45.6	(10.6)	(763)
Accrued Taxes								
Federal Income Tax	154,601	3/	(5,086)	149,515			-6.72%	(10,047)
State Income Tax	54,478	3/	(960)	53,518			-11.72%	(6,272)
PA Gross Receipts Tax	98,416	3/	(3,405)	95,011			22.87%	21,729
PA Capital Stock Tax	30,553	3/	(512)	30,041			-11.72%	(3,521)
PA Public Utility Realty Tax	38,783	3/	0	38,783			14.53%	5,635
Total	$1,946,722		($11,832)	$1,856,473				($9,589)
Amount Per Company								(11,571)
Adjustment to Cash Working Capital								$1,982

Notes:

1/ Exhibit JMK 2, Page 42.

2/ Rate Base multiplied by the long-term debt and preferred debt ratios.

3/ Pennsylvania Jurisdictional amount at present rates.

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Adjustments to Net Income
Test Year Ending September 30, 1995
($000)

	Pennsylvania Jurisdictional Amount	Source
Net Income per Company	$366,622	Schedule TSC - 1, Page 1
OCA Adjustments:		
Benefits Savings	99	Schedule TSC - 8
Postretirement Benefits - Discount Rate	416	Schedule TSC - 9
Pension Expense - Discount Rate	10,642	Schedule TSC - 10
Prior Period SFAS No. 106 Costs	1,555	Schedule TSC - 11
Disallow SFAS No. 112	592	Schedule TSC - 12
Interest on Customer Deposits	34	Schedule TSC - 13
Revision of Nuclear Decommisssioning Funding	7,093	Schedule TSC - 14
Nuclear Decommisssioning Costs Disallowance	2,928	Schedule TSC - 15
Fossil Decommissioning Expense	24,902	Schedule TSC - 16
Susquehanna Early Window Deferrals	1,199	Schedule TSC - 17
Susquehanna Refueling Outage Costs	643	Schedule TSC - 18
Environmental Remediation	1,745	Schedule TSC - 19
Depeciation Expense	26,556	Schedule TSC - 20
EDI/IDI Credits	7,006	Schedule TSC - 21
Uncollectibles From Gross Receipts Tax	431	Schedule TSC - 22
Eliminate Additions to Taxable Income	5,810	Schedule TSC - 23
Eliminate Potential Tax Deficiencies	1,017	Schedule TSC - 24
Consolidated Tax Savings	2,161	Schedule TSC - 25
Interest Synchronization	(200)	Schedule TSC - 26
Total OCA Adjustments	$94,629	
Total Adjusted Income per OCA	$461,251	

PENNSYLVANIA POWER & LIGHT COMPANY

Summary of Adjustments to Net Income
Test Year Ending September 30, 1995
($000)

	Revenues	Operation & Maintenance	Gains on Allow. and Reg. Debits & Credits	Depreciation & Amortization	Taxes Other Than Income	State Income Tax	Federal Income Tax	Deferred Federal Income Tax	Investment Tax Credit	Net Operating Income
Net Income per Company	$2,402,255	$1,372,927	($29,674)	$320,797	$186,553	$54,478	$154,601	($15,424)	($8,625)	$366,622
OCA Adjustments:										
Benefits Savings	0	(171)	0	0	0	19	53	0	0	99
Postretirement Benefits - Discount Rate	0	(416)	0	0	0	0	0	0	0	416
Pension Expense - Discount Rate	0	(10,642)	0	0	0	0	0	0	0	10,642
Prior Period SFAS No 106 Costs	0	(1,555)	0	0	0	0	0	0	0	1,555
Disallow SFAS No. 112	0	(592)	0	0	0	0	0	0	0	592
Interest on Customer Deposits	0	(58)	0	0	0	6	18	0	0	34
Revision of Nuclear Decommissioning Funding	0	(11,593)	0	0	0	1,174	3,326	0	0	7,093
Nuclear Decommisssioning Costs Disallowance	0	(5,022)	0	0	0	546	1,548	0	0	2,928
Fossil Decommissioning Expense	0	(43,041)	0	0	0	4,730	13,409	0	0	24,902
Susquehanna Early Window Deferrals	0	(1,199)	0	0	0	0	0	0	0	1,199
Susquehanna Refueling Outage Costs	0	(1,111)	0	0	0	122	346	0	0	643
Environmental Remediation	0	(3,017)	0	0	0	332	940	0	0	1,745
Depeciation Expense	0	0	0	(40,855)	0	0	0	14,299	0	26,556
EDI/IDI Credits	12,666	0	0	0	557	1,331	3,772	0	0	7,006
Uncollectibles From Gross Receipts Tax	0	0	0	0	(745)	82	232	0	0	431
Eliminate Additions to Taxable Income	0	0	0	0	0	(1,515)	(4,295)	0	0	5,810
Eliminate Potential Tax Deficiencies	0	0	0	0	0	(213)	(804)	0	0	1,017
Consolidated Tax Savings	0	0	0	0	0	0	(2,161)	0	0	2,161
Interest Synchronization	0	0	0	0	0	52	148	0	0	(200)
Total OCA Adjustments	$12,666	($78,417)	$0	($40,855)	($188)	$6,666	$16,532	$14,299	$0	$94,629
Total Adjusted Income per OCA	$2,414,921	$1,294,510	($29,674)	$279,942	$186,365	$61,144	$171,133	($1,125)	($8,625)	$461,251

Docket No. R-00943271
Schedule TSC-8

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Recognize Benefits Savings
Associated with Year End Employees & Wages
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Adjustments to Reflect Year End Wages (2)	$(916)	(793)
Benefits and Payroll Tax Ratio (3)	31.3%	31.3%
Adjustment to Benefits Expense	$(287)	$(248)
Percent to O&M (4)	68.7%	68.7%
Adjustment to O&M	$(197)	$(171)
State Income Tax at 10.99%	22	19
Federal Income Tax at 35%	61	53
Adjustment	$ 114	$ 99

Notes:

(1) Reflects ratio of 86.5872% per Exhibit JMK-2.

(2) Per Schedule D-5 of Exhibit Future 1.

(3) Per response to OCA IV-75.

(4) Ratio applicable to benefits per Exhibit Future 1, Schedules D-6 and D-10.

Docket No. R-00943271
Schedule TSC-9

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Postretirement Benefits Expense
to Reflect Revised Discount Rate
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Change in Postretirement Benefits Cost Resulting from Updating Discount Rate to 8.5% (2)	$(700)	$(606)
Percent to O&M (3)	68.7%	68.7%
Adjustment to O&M Expense	$(481)	$(416)
State Income Tax (4)	0	0
Federal Income Tax (4)	0	0
Adjustment to Net Income	$481	$416

Notes:

(1) Reflects ratio of 86.5518% per Exhibit JMK-2 and response to OTS-RE-3D.

(2) Per response to On the Record Data Request DR-OCA-1.

(3) Per Schedule D-6 of Exhibit Future 1.

(4) Adjustment has no income tax effects since expense was not recognized as tax deductible in Company's filing.

Docket No. R-00943271
Schedule TSC-10

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Pension Expense to Reflect Revised Discount Rate Test Year Ending September 30, 1995 ($000)

	Total Company	Pennsylvania Jurisdictional (1)
Pension Cost Per OCA (2)	$ 0	0
Amount per Company Filing (3)	17,898	15,491
Adjustment to Pension Cost	$(17,898)	$(15,491)
Percent to O&M (4)	68.7%	68.7%
Adjustment to O&M Expense	$(12,296)	$(10,642)
State Income Tax (5)	0	0
Federal Income Tax (5)	0	0
Adjustment to Net Income	$ 12,296	$10,642

Notes:

(1) Reflects ratio of 86.5518% per Exhibit JMK-2 and response to OTS-RE-3D.

(2) Reflects estimated cost based on an 8.5 percent discount rate.

(3) Per OCA IV-102 & OTS-RE-3D.

(4) Percent applicable to benefits per Exhibit Future 1, Schedules D-6 and D-10.

(5) Adjustment has no income tax effects since expense was not recognized as tax deductible in Company's filing.

Docket No. R-00943271
Schedule TSC-11

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Disallow
Prior Period SFAS No. 106 Costs
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Adjustment to Disallow the Amortization of Prior Period SFAS No. 106 Costs (2)	$(1,797)	$(1,555)
State Income Tax (3)	0	0
Federal Income Tax (3)	0	0
Adjustment to Net Income	$1,797	$1,555

Notes:

(1) Reflects ratio of 86.5518% applicable to benefit per Exhibit JMK-2 and response to OTS-RE-3D.

(2) Per Schedule D-6 of Exhibit Future 1.

(3) Adjustment has no income tax effects since expense was not recognized as tax deductible in the Company's filing.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Disallow SFAS No. 112 Accrual
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
SFAS No. 112 Accrual (2)	$ 996	$ 862
Percent to O&M (3)	68.70%	68.70%
Adjustment to O&M	$ (684)	$ (592)
State Income Tax (4)	0	0
Federal Income Tax (4)	0	0
Adjustment to Net Income	$ 684	$ 592

Notes:

(1) Reflects ratio of 86.5518% per Exhibit JMK-2 and response to OTS-RE-3D.

(2) Per response to OCA IV-106 and OTS-RE-105D.

(3) Percent applicable to benefits per Exhibit Future 1, Schedules D-6 and D-10.

(4) Adjustment has no income tax effects since expense was not recognized as tax deductible in the Company's filing.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Revise
Interest Rate Applicable to Customer Deposits
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Balance of Customer Deposits (1)	$1,106	$1,106
Revised Interest Rate (2)	5.77%	5.77%
Revised Interest Expense	$ 64	$ 64
Amount per Company (3)	122	122
Adjustment to Expense	$ (58)	$ (58)
State Income Tax at 10.99%	6	6
Federal Income Tax at 35%	18	18
Adjustment to Net Income	$ 34	$ 34

Notes:

(1) Per Exhibit Future 1, Schedule C-1

(2) Per response to OCA IX-20.

(3) Per Exhibit Future 1, Schedule D-9.

Docket No. R-00943271
Schedule TSC-14

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Nuclear Decommissioning Contributions to Reflect Revised Funding Assumptions Test Year Ending September 30, 1995 ($000)

	Total Company	Pennsylvania Jurisdictional (1)
Recommended Funding Contribution		
Susquehanna Unit 1 (2)	$ 6,238	$ 4,894
Susquehanna Unit 2 (3)	9,028	7,083
Total	$ 15,266	$ 11,977
Amount per Company	30,042	23,570
Adjustment to Expense	$(14,776)	$(11,593)
Tax deductible cost per OCA (4)	$ 15,110	$ 11,855
Tax deductible cost per Company	28,720	22,533
Adjustment to taxable income	$ 13,610	$ 10,678
State Income Tax at 10.99%	1,496	1,174
Federal Income Tax at 35%	4,240	3,326
Adjustment to Net Income	$ 9,040	$ 7,093

Notes:

(1) Reflects ratio of 78.456% per Exhibit JMK-2.

(2) Refer to page 2 of this schedule.

(3) Refer to page 3 of this schedule.

(4) Recognizes that only 97.5 percent of Unit 1 decommissioning contributions are tax deductible.

PENNSYLVANIA POWER & LIGHT COMPANY

Susquehanna 1 Decommissioning Model
Trust Fund Summary
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Management Fee [5]	Net Additions	Decomm. Expend [6]	Balance
1	Beginning Balance								$56,548
2	1995	$6,238	0.0720	$1,560	$1,032	$0	$2,591	$0	59,139
3	1996	6,238	0.0720	6,238	4,559	0	10,797	0	69,937
4	1997	6,238	0.0720	6,238	5,351	0	11,589	0	81,525
5	1998	6,238	0.0720	6,238	6,200	0	12,438	0	93,963
6	1999	6,238	0.0720	6,238	7,112	0	13,350	0	107,313
7	2000	6,238	0.0720	6,238	8,090	0	14,328	0	121,641
8	2001	6,238	0.0720	6,238	9,140	0	15,378	0	137,020
9	2002	6,238	0.0720	6,238	10,268	0	16,506	0	153,525
10	2003	6,238	0.0720	6,238	11,477	0	17,715	0	171,241
11	2004	6,238	0.0720	6,238	12,776	0	19,014	0	190,254
12	2005	6,238	0.0720	6,238	14,169	0	20,407	0	210,662
13	2006	6,238	0.0720	6,238	15,665	0	21,903	0	232,565
14	2007	6,238	0.0720	6,238	17,271	0	23,509	0	256,074
15	2008	6,238	0.0720	6,238	18,994	0	25,232	0	281,305
16	2009	6,238	0.0720	6,238	20,843	0	27,081	0	308,387
17	2010	6,238	0.0720	6,238	22,828	0	29,066	0	337,453
18	2011	6,238	0.0720	6,238	24,958	0	31,196	0	368,649
19	2012	6,238	0.0720	6,238	27,245	0	33,483	0	402,132
20	2013	6,238	0.0720	6,238	29,699	0	35,937	0	438,069
21	2014	6,238	0.0720	6,238	32,333	0	38,571	0	476,641
22	2015	6,238	0.0720	6,238	35,160	0	41,398	0	518,039
23	2016	6,238	0.0720	6,238	38,195	0	44,433	0	562,472
24	2017	6,238	0.0720	6,238	41,452	0	47,690	0	610,161
25	2018	6,238	0.0720	6,238	44,947	0	51,185	0	661,346
26	2019	6,238	0.0720	6,238	48,699	0	54,937	0	716,283
27	2020	6,238	0.0720	6,238	52,725	0	58,963	0	775,246
28	2021	6,238	0.0720	6,238	57,047	0	63,285	0	838,531
29	2022	6,238	0.0720	3,119	61,209	0	64,328	(10,123)	892,736
30	2023	0	0.0720	0	63,335	0	63,335	(58,297)	897,775
31	2024	0	0.0720	0	57,014	0	57,014	(244,153)	710,636
32	2025	0	0.0720	0	42,640	0	42,640	(262,397)	490,879
33	2026	0	0.0720	0	27,179	0	27,179	(244,463)	273,595
34	2027	0	0.0720	0	14,549	0	14,549	(152,903)	135,241
35	2028	0	0.0720	0	9,836	0	9,836	(2,127)	142,950
36	2029	0	0.0720	0	10,398	0	10,398	(2,206)	151,142
37	2030	0	0.0720	0	10,996	0	10,996	(2,294)	159,844
38	2031	0	0.0720	0	9,613	0	9,613	(58,412)	111,045
39	2032	0	0.0720	0	4,376	0	4,376	(104,525)	10,896
40	2033	0	0.0720	0	392	0	392	(11,287)	$2
		$174,664		$166,867	$929,773	$0	$1,096,640	($1,153,186)	

Notes:

1) The 1995 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement except for first and last year where partial year amounts are recognized.
4) Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer x Current Year Earnings Rate - 1/2 Decommissioning Expenditure x Current Year Earnings Rate.
5) Reflected as a .3% reduction in earnings rate.
6) PP&L 90% share of costs inflated to future price levels.

PENNSYLVANIA POWER & LIGHT COMPANY

Susquehanna 2 Decommissioning Model
Trust Fund Summary
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Management Fee [5]	Net Additions	Decomm. Expend [6]	Balance
1	Beginning Balance								$41,717
2	1995	$9,028	0.0720	$2,257	$771	$0	$3,028	$0	44,745
3	1996	9,028	0.0720	9,028	3,605	0	12,633	0	57,378
4	1997	9,028	0.0720	9,028	4,531	0	13,559	0	70,937
5	1998	9,028	0.0720	9,028	5,524	0	14,553	0	85,490
6	1999	9,028	0.0720	9,028	6,591	0	15,619	0	101,109
7	2000	9,028	0.0720	9,028	7,736	0	16,764	0	117,874
8	2001	9,028	0.0720	9,028	8,965	0	17,993	0	135,867
9	2002	9,028	0.0720	9,028	10,283	0	19,312	0	155,178
10	2003	9,028	0.0720	9,028	11,699	0	20,727	0	175,906
11	2004	9,028	0.0720	9,028	13,218	0	22,246	0	198,152
12	2005	9,028	0.0720	9,028	14,849	0	23,877	0	222,029
13	2006	9,028	0.0720	9,028	16,599	0	25,627	0	247,656
14	2007	9,028	0.0720	9,028	18,477	0	27,506	0	275,162
15	2008	9,028	0.0720	9,028	20,493	0	29,522	0	304,683
16	2009	9,028	0.0720	9,028	22,657	0	31,685	0	336,369
17	2010	9,028	0.0720	9,028	24,980	0	34,008	0	370,377
18	2011	9,028	0.0720	9,028	27,472	0	36,500	0	406,877
19	2012	9,028	0.0720	9,028	30,147	0	39,176	0	446,053
20	2013	9,028	0.0720	9,028	33,019	0	42,047	0	488,100
21	2014	9,028	0.0720	9,028	36,101	0	45,129	0	533,229
22	2015	9,028	0.0720	9,028	39,409	0	48,437	0	581,666
23	2016	9,028	0.0720	9,028	42,959	0	51,987	0	633,653
24	2017	9,028	0.0720	9,028	46,769	0	55,798	0	689,451
25	2018	9,028	0.0720	9,028	50,859	0	59,887	0	749,338
26	2019	9,028	0.0720	9,028	55,249	0	64,277	0	813,615
27	2020	9,028	0.0720	9,028	59,960	0	68,988	0	882,603
28	2021	9,028	0.0720	9,028	65,016	0	74,045	0	956,647
29	2022	9,028	0.0720	9,028	70,443	0	79,472	0	1,036,119
30	2023	9,028	0.0720	9,028	76,268	0	85,297	0	1,121,416
31	2024	9,028	0.0720	2,257	81,727	0	83,984	(15,260)	1,190,140
32	2025	0	0.0720	0	86,501	0	86,501	(20,325)	1,256,316
33	2026	0	0.0720	0	91,257	0	91,257	(22,938)	1,324,636
34	2027	0	0.0720	0	93,609	0	93,609	(96,697)	1,321,548
35	2028	0	0.0720	0	84,706	0	84,706	(337,739)	1,068,514
36	2029	0	0.0720	0	65,684	0	65,684	(350,932)	783,267
37	2030	0	0.0720	0	44,177	0	44,177	(367,601)	459,843
38	2031	0	0.0720	0	24,035	0	24,035	(268,592)	215,286
39	2032	0	0.0720	0	8,883	0	8,883	(191,587)	32,582
40	2033	0	0.0720	0	1,173	0	1,173	(33,753)	$2
		$270,849		$257,307	$1,406,401	$0	$1,663,708	($1,705,423)	

Notes:

1) The 1995 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement except for first and last year where partial year amounts are recognized.
4) Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer x Current Year Earnings Rate - 1/2 Decommissioning Expenditure x Current Year Earnings Rate.
5) Reflected as a .3% reduction in earnings rate.
6) PP&L 90% share of costs inflated to future price levels.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Decommissioning Contributions
to Reflect Adjustments to Decommissioning Costs
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Funding Contributions Based on OCA Cost		
Susquehanna Unit 1 (2)	$ 3,482	$ 2,732
Susquehanna Unit 2 (3)	5,382	4,223
Total	$ 8,864	$ 6,955
Funding Contributions Based on Company Cost and OCA Funding Assumptions (4)	15,266	11,977
Adjustment to Expense	$(6,402)	$(5,022)
Tax Deduction Based on OCA Cost (5)	8,777	6,887
Tax Deduction Based on Company Cost (4)	15,110	11,855
Adjustment to Taxable Income	$(6,333)	$(4,968)
State Income Tax at 10.99%	696	546
Federal Income Tax at 34%	1,973	1,548
Adjustment to Net Income	$ 3,733	$ 2,928

Notes:

(1) Reflects ratio of 78.456 percent per Exhibit JMK-2.
(2) Refer to page 2 of this schedule.
(3) Refer to page 3 of this schedule.
(4) Refer to Schedule TSC-14.
(5) Recognizes that only 97.5 percent of Unit 1 decommissioning contributions are tax deductible.

PENNSYLVANIA POWER & LIGHT COMPANY

Susquehanna 1 Decommissioning Model
Trust Fund Summary
($000)

			Tax Qualified Trust						
Line No	Year	Revenue · Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Management Fee [5]	Net Additions	Decomm. Expend [6]	Balance
1	Beginning Balance								$56,548
2	1995	$3,482	0.0720	$871	$1,026	$0	$1,896	$0	58,444
3	1996	3,482	0.0720	3,482	4,409	0	7,891	0	66,335
4	1997	3,482	0.0720	3,482	4,987	0	8,469	0	74,805
5	1998	3,482	0.0720	3,482	5,608	0	9,090	0	83,895
6	1999	3,482	0.0720	3,482	6,275	0	9,757	0	93,652
7	2000	3,482	0.0720	3,482	6,990	0	10,472	0	104,123
8	2001	3,482	0.0720	3,482	7,757	0	11,239	0	115,362
9	2002	3,482	0.0720	3,482	8,581	0	12,063	0	127,425
10	2003	3,482	0.0720	3,482	9,465	0	12,947	0	140,372
11	2004	3,482	0.0720	3,482	10,414	0	13,896	0	154,268
12	2005	3,482	0.0720	3,482	11,433	0	14,915	0	169,183
13	2006	3,482	0.0720	3,482	12,526	0	16,008	0	185,191
14	2007	3,482	0.0720	3,482	13,699	0	17,181	0	202,372
15	2008	3,482	0.0720	3,482	14,958	0	18,440	0	220,812
16	2009	3,482	0.0720	3,482	16,310	0	19,792	0	240,604
17	2010	3,482	0.0720	3,482	17,761	0	21,243	0	261,847
18	2011	3,482	0.0720	3,482	19,318	0	22,800	0	284,647
19	2012	3,482	0.0720	3,482	20,989	0	24,471	0	309,118
20	2013	3,482	0.0720	3,482	22,782	0	26,264	0	335,382
21	2014	3,482	0.0720	3,482	24,708	0	28,190	0	363,571
22	2015	3,482	0.0720	3,482	26,774	0	30,256	0	393,827
23	2016	3,482	0.0720	3,482	28,991	0	32,473	0	426,300
24	2017	3,482	0.0720	3,482	31,371	0	34,853	0	461,154
25	2018	3,482	0.0720	3,482	33,926	0	37,408	0	498,562
26	2019	3,482	0.0720	3,482	36,668	0	40,150	0	538,712
27	2020	3,482	0.0720	3,482	39,611	0	43,093	0	581,805
28	2021	3,482	0.0720	3,482	42,769	0	46,251	0	628,056
29	2022	3,482	0.0720	1,741	45,781	0	47,522	(8,771)	666,807
30	2023	0	0.0720	0	47,056	0	47,056	(50,517)	663,346
31	2024	0	0.0720	0	41,287	0	41,287	(203,724)	500,908
32	2025	0	0.0720	0	28,836	0	28,836	(218,847)	310,897
33	2026	0	0.0720	0	15,447	0	15,447	(203,890)	122,454
34	2027	0	0.0720	0	4,409	0	4,409	(126,855)	$8
		$97,496		$93,144	$662,925	$0	$756,068	($812,605)	

Notes:

1) The 1995 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement except for first and last year where partial year amounts are recognized.
4) Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer x Current Year Earnings Rate - 1/2 Decommissioning Expenditure x Current Year Earnings Rate.
5) Reflected as a .3% reduction in earnings rate.
6) PP&L 90% share of costs inflated to future price levels.

PENNSYLVANIA POWER & LIGHT COMPANY

Susquehanna 2 Decommissioning Model
Trust Fund Summary
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Management. Fee [5]	Net Additions	Decomm. Expend [6]	Balance
1	Beginning Balance								$41,717
2	1995	$5,382	0.0720	$1,345	$763	$0	$2,108	$0	43,825
3	1996	5,382	0.0720	5,382	3,406	0	8,787	0	52,613
4	1997	5,382	0.0720	5,382	4,050	0	9,432	0	62,044
5	1998	5,382	0.0720	5,382	4,741	0	10,123	0	72,167
6	1999	5,382	0.0720	5,382	5,483	0	10,865	0	83,032
7	2000	5,382	0.0720	5,382	6,280	0	11,661	0	94,693
8	2001	5,382	0.0720	5,382	7,134	0	12,516	0	107,209
9	2002	5,382	0.0720	5,382	8,052	0	13,433	0	120,642
10	2003	5,382	0.0720	5,382	9,036	0	14,418	0	135,060
11	2004	5,382	0.0720	5,382	10,093	0	15,475	0	150,535
12	2005	5,382	0.0720	5,382	11,227	0	16,609	0	167,144
13	2006	5,382	0.0720	5,382	12,445	0	17,826	0	184,970
14	2007	5,382	0.0720	5,382	13,751	0	19,133	0	204,103
15	2008	5,382	0.0720	5,382	15,154	0	20,535	0	224,638
16	2009	5,382	0.0720	5,382	16,659	0	22,040	0	246,678
17	2010	5,382	0.0720	5,382	18,274	0	23,656	0	270,334
18	2011	5,382	0.0720	5,382	20,008	0	25,390	0	295,723
19	2012	5,382	0.0720	5,382	21,869	0	27,251	0	322,974
20	2013	5,382	0.0720	5,382	23,866	0	29,248	0	352,222
21	2014	5,382	0.0720	5,382	26,010	0	31,392	0	383,613
22	2015	5,382	0.0720	5,382	28,311	0	33,693	0	417,306
23	2016	5,382	0.0720	5,382	30,781	0	36,162	0	453,468
24	2017	5,382	0.0720	5,382	33,431	0	38,813	0	492,281
25	2018	5,382	0.0720	5,382	36,276	0	41,657	0	533,938
26	2019	5,382	0.0720	5,382	39,329	0	44,711	0	578,649
27	2020	5,382	0.0720	5,382	42,606	0	47,988	0	626,637
28	2021	5,382	0.0720	5,382	46,124	0	51,505	0	678,142
29	2022	5,382	0.0720	5,382	49,899	0	55,280	0	733,422
30	2023	5,382	0.0720	5,382	53,951	0	59,332	0	792,755
31	2024	5,382	0.0720	1,345	57,677	0	59,022	(13,257)	838,519
32	2025	0	0.0720	0	60,824	0	60,824	(17,658)	881,685
33	2026	0	0.0720	0	63,907	0	63,907	(19,928)	925,664
34	2027	0	0.0720	0	64,832	0	64,832	(83,770)	906,726
35	2028	0	0.0720	0	56,225	0	56,225	(284,290)	678,661
36	2029	0	0.0720	0	39,109	0	39,109	(295,396)	422,374
37	2030	0	0.0720	0	19,819	0	19,819	(309,428)	132,764
38	2031	0	0.0720	0	4,780	0	4,780	(137,540)	$3
		$161,445		$153,373	$966,183	$0	$1,119,555	($1,161,269)	

Notes:

1) The 1995 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement except for first and last year where partial year amounts are recognized.
4) Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer x Current Year Earnings Rate - 1/2 Decommissioning Expenditure x Current Year Earnings Rate.
5) Reflected as a .3% reduction in earnings rate.
6) PP&L 90% share of costs inflated to future price levels.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Eliminate
Accrual for Decommissioning Fossil Units
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional
Adjustment to Eliminate Expense (1)	$(52,818)	$(43,041)
State Income Tax at 10.99%	5,805	4,730
Federal Income Tax at 35%	16,455	13,409
Adjustment to Net Income	$30,558	$24,902

Notes:

(1) Amount per Schedule D-12 of Exhibit Future 1. Jurisdictional amount per page 42 of Exhibit JMK-2.

Docket No. R-00943271
Schedule TSC-17

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to
of Susquehanna Early Window Deferrals
Test Year Ending September 30, 1995
($000)

	Amount (1)
Adjustment to Eliminate Annual Amortization of Deferral (2)	$(1,199)
State Income Tax (3)	0
Federal Income Tax (3)	0
Adjustment to Net Income	$1,199

Notes:

(1) Full amount of amortization is allocable to the Pennsylvania jurisdiction.

(2) Per Schedule D-14 of Exhibit Future 1.

(3) Adjustment has no tax effects since expense was not recognized as tax deductible in the Company's filing.

Docket No. R-00943271
Schedule TSC-18

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to the Amortization of
Susquehanna Refueling Outage Costs
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Susquehanna Unit 1 Reload 8 Costs Subject to Amortization (1)	$ 16,502	
Amortization Period (5/22/95 - 11/4/96) (1)	532 days	
Annual Amortization	$ 1,322	$8,885
Susquehanna Unit 2 Reload 7 Costs Subject to Amortization (1)	14,642	
Amortization Period (11/13/95 - 5/19/97) (2)	553 days	
Annual Amortization	$ 9,664	$7,585
Total Annual Refueling Outage Costs	$ 20,986	$16,470
Amount Per Company (1)	22,402	17,581
Adjustment to Expense	$ (1,416)	$(1,111)
State Income Tax at 10.99%	156	122
Federal Income Tax at 35%	441	346
Adjustment to Net Income	$ 819	$ 643

Notes:

(1) Per response to OCA IX-14

(2) Per response to DR-OCA-3.

Docket No. R-00943271
Schedule TSC-19

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Environmental Remediation Costs
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Environmental Remediation Expenses based on Actual Experience (2)	$ 1,697	$ 1,383
Amount per Company (3)	5,400	4,400
Adjustment to O&M Expense	$(3,703)	$(3,017)
State Income Tax at 10.99%	407	332
Federal Income Tax at 35%	1,154	940
Adjustment to Net Income	$2,142	$1,745

Notes:

(1) Reflects factor of 81.4815% per Exhibit JMK-2.

(2) Reflects 12 months ended February 1995 per responses to OCA IV-99 and DR-OCA-6.

(3) Per Schedule D-16 of Exhibit Future 1.

Docket No. R-00943271
Schedule TSC-20

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Depreciation Expense
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Adjustment to Depreciation Expense (1)	$(51,028)	$(40,855)
Deferred Federal Income Tax Effect	17,860	14,299
Adjustment to Net Income	$33,168	$26,556

Note:

(1) Per testimony of Dr. Charles E. Johnson.

Docket No. R-00943271
Schedule TSC-21

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to EDI/IDI Credits
Test Year Ending September 30, 1995
($000)

	Amount (1)
EDI/IDI Credits to be Absorbed by Company (2)	$12,666
Gross Receipts Tax at 4.4%	557
Adjustment to Taxable Income	$12,109
State Income Tax at 10.99%	1,331
Federal Income Tax at 35%	3,772
Adjustment to Net Income	$7,006

Note:

(1) The full amount of the credits are allocable to Pennsylvania jurisdictional operations.

(2) Per testimony of Dr. Charles E. Johnson.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Gross Receipts Tax to Exclude Uncollectibles Test Year Ending September 30, 1995 ($000)

	Amount (1)
Uncollectibles Expense per Company (2)	$16,932
Gross Receipts Tax Rate	.044
Adjustment to Gross Receipts Tax	$ 745
State Income Tax at 10.99%	82
Federal Income Tax at 35%	232
Adjustment to Net Income	$ 431

Notes:

(1) Full amount of uncollectibles expense and, therefore, total adjustment is allocable to Pennsylvania jurisdictional operations.

(2) Per response to OCA IV-56.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Eliminate Certain Additions to Taxable Income
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Adjustment to Taxable Income to Eliminate Additions for:		
ECR/FAC Overrecovery (2)	$(9,690)	$(9,690)
Refueling Outage Costs (2)	(2,724)	(2,138)
Bad Debt Accrual (2)	(1,959)	(1,959)
Adjustment to Taxable Income	$(14,373)	$(13,787)
State Income Tax at 10.99%	(1,580)	(1,515)
Federal Income Tax at 35%	(4,478)	(4,295)
Adjustment to Net Income	$ 6,058	$5,810

Notes:

(1) Per Exhibit JMK-2.

(2) Per Schedule D-19 of Exhibit Future 1.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Eliminate
Accruals for Potential Tax Deficiencies
Test Year Ending September 30, 1995
($000)

	Total Company	Pennsylvania Jurisdictional (1)
Reverse State Tax Accrual (2)	$ (252)	$ (213)
Reverse Federal Tax Accrual (2)	(948)	(804)
Total Adjustment to Net Income	$1,200	$1,017

Notes:

(1) Per Exhibit JMK-2

(2) Per Schedule D-19 of Exhibit Future 1.

PENNSYLVANIA POWER & LIGHT COMPANY

Adjustment to Recognize
Consolidated Tax Savings
Test Year Ending September 30, 1995
($000)

	Taxable Income (1)		
	1993	1994	Test Year
Lady Jane	$ (395)	$ (686)	$ (590)
Realty Co. of Pennsylvania	(419)	(240)	(239)
Pennsylvania Mines Corp. (2)	(5,804)	(6,384)	(5,225)
Rushton Mining	(551)	(345)	(529)
Power Mktg. Development	N/A	(601)	N/A
Total Loss Companies	$ (7,169)	$ (8,256)	$ (6,583)
CEP Group Inc.	1,100	0	1,300
Green Manor Coal Co.	2,984	3,100	3,265
Pennsylvania Power & Light	462.395	504,740	548,752
Total Gain Companies	$466,479	$507,840	$553,317
Percent of Gain from PP&L	99.125%	99.390%	99.175%
Total Loss	(7,169)	(8,256)	(6,583)
Loss Allocable to PP&L	$ (7,106)	$ (8,206)	$ (6,529)
Average Tax Loss Allocable to PP&L			$ 7,280
Federal Income Tax Rate			35%
Consolidated Tax Savings			$ 2,548
Jurisdictional Percentage (3)			84.81%
Jurisdictional Consolidated Tax Savings			$ 2,161

Notes:

(1) Amounts for 1993 and the 1995 test year per Attachment II-D-23b of PP&L Filing Requirements. Amount for 1994 response to OCA IV-121. Interstate Energy Corporation has been excluded since income fluctuates between gains and losses and normalized income is expected to be $0.

(2) Pennsylvania Mines Corporation had a tax loss of $21,616,200 on 1993. However, this loss reflected mine closing costs. Therefore, the average of 1994 and 1995 test year amounts were used for 1993.

(3) Reflects percentage applicable to adjustments to federal income taxes per Exhibit JMK-2.

Docket No. R-00943271
Schedule TSC-26

PENNSYLVANIA POWER & LIGHT COMPANY

Interest Synchronization Adjustment
Test Year Ending September 30, 1995
($000)

	Amount
OCA Recommended Rate Base	$4,896,679
Weighted Cost of Debt	3.79%
Synchronized Interest Expense	$185,584
Interest Expense per Company	$186,059
Change in Interest Expense	($475)
State Income Tax	$52
Federal Income Tax	$148

Docket No. R-00943271
Schedule TSC-27

PENNSYLVANIA POWER & LIGHT COMPANY

Reconciliation of State and Federal Income Taxes
Test Year Ending September 30, 1995
($000)

Description		Test Year Adjusted Per Company	OCA Adjustments	Test Year at Present Rates	OCA Proforma Increase	Test Year at Proposed Rates
CALCULATION OF STATE INCOME TAX						
Net Operating Income Before Income Taxes		$493,686	$132,126	$625,812	($69,392)	$556,420
Net Adjustments for State Taxable Income		83	(69,540)	(69,457)	0	(69,457)
State Taxable Income		$493,769	$62,586	$556,355	($69,392)	$486,963
State Income Tax at	10.99%	$54,265	$6,878	$61,143	($7,626)	$53,517
State Income Tax Adjustments		213	(213)	0	0	0
Total State Income Tax		$54,478	$6,665	$61,143	($7,626)	$53,517
CALCULATION OF FEDERAL INCOME TAX						
Net Operating Income Before Income Taxes		$493,686	$132,126	$625,812	($69,392)	$556,420
Net Adjustments for Federal Taxable Income		0	(75,714) 1/	(75,714)	0	(75,714)
State Income Tax		(54,265)	(6,878)	(61,143)	7,626	(53,517)
Federal Taxable Income		$439,421	$49,534	$488,955	($61,766)	$427,189
Federal Income Tax at	35.0%	$153,797	$17,337	$171,134	($21,618)	$149,516
Federal Tax Adjustment		804	(804)	0	0	0
Total Federal Income Tax		$154,601	$16,533	$171,134	($21,618)	$149,516
Total Calculated Current Taxes		$209,079	$23,198	$232,277	($29,244)	$203,033
Total Current Taxes (Schedule TSC-1, Page 1)		209,079	23,198	232,277	(29,244)	203,033
Difference		$0	$0	$0	$0	$0

Notes:
1/ Includes the adjustment for consolidated tax savings.