Sierra Club Stmt No. 1
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BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF PENNSYLVANIA

In the Matter of Pennsylvania Power)
& Light Company's General Rate Case) Docket No. R-00943271

SIERRA CLUB STATEMENT # 1:

TESTIMONY

OF

BRUCE BIEWALD

On behalf of:

SIERRA CLUB OF PENNSYLVANIA

April 12, 1995

TELLUS INSTITUTE
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1. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce Biewald. My business address is 11 Arlington Street, Boston, MA 02116.

Q. PLEASE DESCRIBE YOUR EMPLOYMENT.

A. I am manager of the electricity program of the Tellus Institute's energy group. The electricity program provides technical and policy advice to public agencies and private organizations in all areas of policy, planning and regulation of electric utilities. I have attached as Sierra Club Exhibit No. 1A the Electricity Program brochure. The program seeks to ensure the appropriate consideration of environmental, economic and equity impacts of developing and using electric energy. Guided by this objective, program staff conduct long-term research projects and participate in dozens of state and federal regulatory proceedings each year. Recent electricity program clients include the U.S. Department of Energy, the U.S. Environmental Protection Agency, the National Association of Regulatory Utility Commissioners, the Tennessee Valley Authority, the Energy Foundation, and consumer advocates and state regulatory commissions in numerous jurisdictions throughout the U.S. We were recently awarded a project for NARUC to identify tools and methods to promote the consideration of environmental quality in electric resource selection decisions in a restructured electric utility industry.

I have been employed at Tellus (formerly ESRG) since 1980, where I have worked on energy-related research, particularly research related to the regulation, planning and operation of electric utility systems. More specifically, I have studied issues in the areas of demand forecasting, demand-side management, rate and fuel adjustment clause analysis, power costs, electric utility dispatch and reliability modelling, generation planning, avoided cost analysis and environmental externalities. My resume is supplied as Sierra Club Exhibit No. 1B.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received my Bachelor of Science degree from the Massachusetts Institute of Technology, where I studied art, architecture and building technology, focusing upon the use of energy in buildings.

Q. HAVE YOU WRITTEN AND PRESENTED PAPERS ON ELECTRIC POWER ISSUES?

A. Yes. I have made presentations on energy and environmental issues at conferences and workshops sponsored by the International Atomic Energy Agency (in Vienna, Austria), the British Columbia Utilities Commission, the Canadian Electrical Association, the Electric Power Research Institute (EPRI), the Latin American Energy Organization (OLADE, in Quito, Ecuador), the National Association of Regulatory Utility Commissioners, the National Association of Utility Consumer Advocates, the Swedish Environmental Protection Agency (in Solna, Sweden), the U.S. Agency for International Development, and the Vermont State Nuclear Advisory Panel. My papers have been published in the *Electricity Journal*, the *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and various conference proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE PUBLIC UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified on a variety of electric utility operating and planning issues in approximately 25 proceedings before regulatory commissions in Arizona, Arkansas, British Columbia, California, Colorado, Delaware, Florida, Indiana, Kentucky, Maine, Maryland, Massachusetts, Michigan, Nevada, New Hampshire, Pennsylvania and Wisconsin.

Q. HAS YOUR TESTIMONY SERVED AS THE BASIS FOR REGULATORY COMMISSION DECISIONS?

A. Yes, in many cases. The Michigan Public Service Commission has adjusted Consumers Power Company and Detroit Edison Company recovery of power costs based upon my recommendations. The Massachusetts Department of Public Utilities adopted the set of monetary values for air pollutants developed by Tellus and supported in my testimony. The California Public Utilities Commission adjusted a utility estimate of nuclear decommissioning costs by approximately $100 million, based upon my testimony. In addition, my recommendations have been reflected in settlement agreements in cases on excess capacity, avoided costs and power plant performance.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Sierra Club.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has two purposes:

First, I was asked to respond to the Pennsylvania Public Utility Commission's 1993 DSM Cost Recovery Order and the Commonwealth Court appellate decision reviewing it, setting out a basis for the incorporation into PP&L rates of DSM cost recovery.

Second, I was asked to provide an alternative to the PP&L rate design proposals offered in this case, providing the Commission with the basis for rate mechanisms that will help insure reliable low-cost power for PP&L customers, given opportunities for DSM and possible electric industry changes between now and PP&L's likely next rate case.

2. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My primary conclusions and recommendations are summarized as follows:

Financial Incentives for DSM - Conclusions

1. Financial incentives for DSM are important to overcome the many economic and institutional barriers to utility DSM.

2. Three general criteria should be used in designing successful DSM incentives: (a) the incentives should make the utility's least-cost plan its most profitable plan, (b) the impacts of the incentive should be large enough to capture the attention of management and stockholders, while maintaining acceptable rate impacts, and (c) the incentive should be simple, understandable, and easy to administer.

3. A variety of mechanisms are available, including shared savings, bounty and bonus mechanisms. Shared savings schemes offer the greatest advantages in terms of encouraging utilities to maximize DSM savings while minimizing program costs.

4. There are two distinct approaches to recovering DSM incentives: a base rate adjustment and an annual surcharge. DSM incentives that are recovered through surcharges are more effective than base rate adjustments, because they are less risky to the utility and they provide incentives that are more closely correlated to the timing of the DSM planning and implementation.

5. I understand that, in the recent DSM Cost Recovery orders of December, 1993, and April, 1994, the Commission established performance-based financial incentives for DSM programs. However, I also understand that the Commonwealth Court's January 9, 1995, Opinion and Order denied surcharge-based recovery of incentives. I also am aware that the Commission appealed

the Commonwealth Court Order in an April 6, 1995, filing with the Pennsylvania Supreme Court.

Financial Incentives for DSM - Recommendations

1. If the Pennsylvania Supreme Court ultimately allows it, I recommend that utilities should be allowed the option of recovering DSM financial incentives through a surcharge.

2. If a surcharge cannot be used to recover DSM financial incentives, then in future rate cases the Commission should establish a base rate adjustment which provides PP&L with a financial incentive for DSM savings achieved within the test year.

3. DSM financial incentives should be calculated on the basis of shared savings, where "savings" equal the difference between long-run avoided costs and utility DSM program costs. Fifteen percent of these savings would provide an appropriate level of incentive to the utility. A system could also be designed to use a near-term measure of savings value, such as the price of off-system sales.

4. PP&L should only be allowed to recover a financial incentive once it has achieved 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan.

Recovery of Net Lost Revenues from DSM - Conclusions

1. Failure to recover lost revenues from successful DSM programs creates a significant financial disincentive for utility DSM programs.

2. Regulatory commissions in at least 21 states have established various mechanisms to allow utilities to recover lost revenues. In general, utilities that are provided net lost revenue adjustments (NLRAs) have implemented more successful and more aggressive DSM programs.

3. The three primary conditions for a successful NLRA are: (a) avoiding a strict "ex post" approach to DSM measurement, (b) involving stakeholders in the NLRA establishment and measurement process, and (c) setting conditions for lost revenue recovery related directly to DSM program operation and performance.

4. I am aware that the Commission has accepted the principle of NLRAs in its 1993 DSM Cost Recovery Order. However, as I understand it, the Commonwealth Court remanded the Commission's order for the calculation methodology of lost revenues.

5. The calculation of lost revenues is relatively straightforward. There are three basic steps involved: (a) the Commission establishes a protocol for measuring the DSM savings, (b) the fixed cost component of retail rates is determined, and (c) for each rate class the fixed cost ~~percentage~~ portion is multiplied by the total DSM savings to determine total net lost revenue. 4/27/95 BF

Recovery of Net Lost Revenues from DSM - Recommendations

1. As provided in the DSM Cost Recovery case, the Commission should establish a Net Lost Revenue Adjustment (NLRA) mechanism to support PP&L's DSM.

2. The Commission should provide for the recovery of PP&L lost revenues through base rates, in accordance with the Commonwealth Court's order on this topic. Utilities should also be allowed special rate relief to make annual adjustments to lost revenue recovery to reflect actual DSM savings achieved.

3. The Commission should grant PP&L annual recovery of all net lost revenues if the Company meets 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan. Otherwise, no recovery should be allowed by the Commission.

4. Separately, the Commission should establish in a remand docket the generic treatment for NLRAs for DSM, presumably consistent with that provided here.

5. The process for estimating and verifying lost revenues should be based on program participation, and not on a strict ex post approach.

Economic Discount Rates - Conclusions

1. Economic discount rates have the potential for creating inequities among customer classes.

2. It is possible to reduce the amount of the rate discount, and therefore any associated inequities, by structuring the tariffs to require participating customers to adopt cost effective DSM measures. An efficiency requirement can be included in the terms and conditions for the discounted rate.

3. To the extent that utility shareholders absorb some of the revenues that are lost as a result of economic discount rates, the utility will have an incentive to minimize the amount of the discount rate, through negotiations with the customer and with cost-effective DSM programs.

4. It is possible to reduce the inequities created by discount rates by providing all customers with access to cost-effective DSM programs.

Economic Discount Rates - Recommendations

1. The Commission should require that large industrial or commercial customers demonstrate through certified energy audits and proof of work done that they have already implemented, or have made a commitment to implement, maximum cost-effective DSM measures before they may participate in PP&L's discount rate programs.

2. PP&L should be required to minimize the inequities caused by economic discount rates by providing a meaningful option for cost-effective DSM programs to all customers.

Recovery of DSM Costs Through a System Benefits Charges - Conclusions

1. As the debate over electric utility industry restructuring has evolved, utilities have become increasingly concerned that price increases due to DSM cost recovery will place them at a competitive disadvantage and encourage large customers to leave the system.

2. Cost-effective DSM programs provide a variety of resource benefits that accrue to *all customers* on the utility system.

3. A "system benefits" charge can be designed to ensure that all customers pay for their share of the DSM program costs, and to prevent uneconomic bypass of a utility system. The charge would be "volumetric", assigned on the basis of consumption, rather than a customer, basis.

4. A system benefits charge would enable PP&L to recover all appropriate DSM costs under a variety of future restructuring and competition scenarios, and would not place PP&L at a competitive disadvantage with regard to retail wheeling or self-generation. Appropriately designed, a system benefits charge may also provide the vehicle for this Commission to position Pennsylvania utilities for industry restructuring.

Recovery of DSM Costs Through System Benefits Charges - Recommendations

1. The Commission should establish a non-bypassable system benefits charge for recovering DSM costs.

2. The Commission should establish a DSM cost recovery mechanism which (a) allows PP&L to recover all appropriate DSM program costs, (b) prevents uneconomic bypass, and (c) will be appropriate under a variety of future electricity industry restructuring scenarios.

3. The Commission should make all approved DSM programs, including low income and other DSM programs, subject to the non-bypassable system benefits charge. The Commission should also consider including other utility expenditures in the charge, perhaps those for environmental benefits.

3. DSM: INCENTIVES FOR DSM

The Case for Financial Incentives

Q. IN YOUR OPINION, IS IT DESIRABLE TO HAVE FINANCIAL INCENTIVES FOR DSM?

A. Yes. I believe it is important to have an incentive based on the Company's performance in developing demand-side management opportunities.

Q. WHAT ARE THE REASONS FOR INTRODUCING AN INCENTIVE MECHANISM?

A. A utility's successful implementation of a least-cost plan should be its most financially attractive course of action. The existence of powerful economic and institutional barriers to DSM provides the first reason for financial incentives. Some of these barriers are due to the very nature of demand-side resources. Unlike power plants and transmission lines, a demand-side resource consists mostly of investment in the efficiency of the equipment owned and used by the utility's customers. For example, utility investments may be in efficient refrigerators, motors or fluorescent light bulbs, or in improved insulation. These are on the customer side of the meter. Thus, DSM changes the very nature of utility investment. This change in ownership creates disincentives for the utility, as I will explain below.

The second reason is that it is necessary to induce changes in the "corporate culture" of many utilities, one which has traditionally favored supply-side construction projects. Construction of supply-side resource additions may create financial stresses and strains for a utility. However, in the long run, construction projects are traditionally seen as the additions to rate base on which a utility earns a return for its shareholders. DSM does not provide the same opportunities for additions to rate base, and therefore, it will take an incentive to make DSM as attractive and profitable as the successful addition of supply-side resources.

The third reason is to reward a utility for achievement. A utility which performs admirably in providing DSM programs which reduce total costs should be rewarded.

Q. WHY IS IT IMPORTANT THAT UTILITIES BE ENTHUSIASTIC SUPPORTERS OF DSM?

A. Traditionally, regulators have felt that they could use a "command and control" approach to ensure that utilities make good on their responsibility to provide safe, reliable service at least cost. While command and control is still important, its usefulness is more limited than it has been in the past, for two main reasons:

- In the past, utility resource acquisition meant primarily supply-side investment, much of it in large units. Demand-side resources involve decentralized decisions and activities on the customer side of the meter. Command and control works less well with many small decisions than with a few large ones.

- In the increasingly competitive electricity industry, utilities seek greater flexibility to respond to customers' needs and interests.

Q. IS THERE ANY EVIDENCE THAT UTILITIES NEED ADDITIONAL MOTIVATION TO PLAN FOR AND IMPLEMENT DSM PROGRAMS?

A. Yes. Many utilities have "concerns" about risks associated with DSM. While a utility could view DSM as an opportunity to become more competitive by improving its array of energy services, it is more common for utilities to view competition (or actually uncertainty about competition) as a reason not to offer comprehensive DSM programs.

One way to get utilities to pursue what they see as a desirable but risky course, is to provide shareholders a reward for excellent performance.

Q. WHAT FEATURES SHOULD THE PP&L INCENTIVE PLAN HAVE?

A. I propose the following criteria by which to evaluate alternative incentive schemes.

1) **The incentives should make the utility's least-cost plan its most profitable plan.** To the extent possible, they should be performance-based, encouraging the utility to maximize the net benefits to PP&L's service territory, or, equivalently, to minimize the total resource cost of providing energy services. They should reward the utility for saving both energy and capacity. There are three elements to the objective of maximizing net benefits:

   (a) The incentive structure should be designed to reward the delivery of energy savings in an efficient manner. The incentives should reward utilities for controlling costs, not for the amount spent on conservation.

   (b) The utility should, ideally, be encouraged to continue to spend money efficiently on conservation programs up to, but not beyond, the point where the costs are equal to the benefits. Over-emphasis on minimizing costs can result in "cream-skimming" or foregoing achievable energy savings.

   (c) The incentives should not reward "gaming", e.g. over-estimating the likely savings of programs.

2) **The impacts of the incentives should be appropriate.**

   (a) The incentive available to the company should be large enough to capture the attention of management and stockholders.

   (b) Ratepayer impacts should be acceptable.

   (c) The system, at this stage, should ~~not~~ be symmetrical. PP&L should be rewarded if it performs exceptionally, ~~but not~~ and penalized if it fails to meet a minimum level. Together with the performance-based

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requirement, this means the Commission should set reasonable demand-side targets for both savings and cost-effectiveness, and establish levels at which rewards take effect.

3) **The mechanisms should be practical.** They should be simple, understandable and easy to administer. It is important that a utility's customers and its officers, managers, and employees understand what the incentives are and how they operate. It does little good to create a complicated incentive system if no one at the Company understands how their actions influence Company earnings. It is also important to be able to explain the system clearly and concisely to the public, state legislators, and other interested parties.

Q. PLEASE DISCUSS THE REASONS TO HAVE REWARDS AND PENALTIES IN THE INCENTIVE SCHEME YOU DESCRIBE ABOVE.

A. A fair incentive scheme would be one which provides symmetrical rewards and penalties. Such a scheme might be based on a reasonable target level of conservation, around which level there would be a "dead band" of plus or minus a fixed percentage. Achievement by the utility of a level of conservation within that band would result in neither rewards nor penalties. If the utility exceeded the upper limit of the band, rewards would be earned, and if it failed to reach the lower end of the band, penalties would be imposed.

Types of Incentive Schemes

Q. WHAT TYPES OF INCENTIVE SCHEMES ARE AVAILABLE?

A. There are a number of different types of incentive schemes. Below I will discuss the leading alternatives -- shared savings and bounty schemes.

Q. PLEASE DESCRIBE THE SHARED SAVING INCENTIVE.

A. **Shared saving** is a common kind of incentive mechanism today. Under this approach the utility keeps a fraction of the net benefit achieved by its DSM programs. Net benefit is the savings in "avoided costs" of energy and capacity less the costs of the DSM program. The fraction kept is typically 10-20 percent, but sometimes as low as 5 percent.

Q. PLEASE DISCUSS THE POSITIVE AND NEGATIVE FEATURES OF SHARED SAVINGS SCHEMES.

A. The unique advantage of shared savings schemes is that they directly reward the utility for the creation of value, by allowing the utility to keep a portion of it. In this manner, they reward any move in the direction of the utility's least-cost plan. The magnitude of the utility's reward is determined by setting the percentage of the net benefits which are retained by the utility, and so both the utility and ratepayers receive shares in the value created.

Q. WHAT DISADVANTAGES DO SHARED SAVINGS SCHEMES HAVE?

A. The difficulty with a shared saving mechanism is the danger of "cream skimming". A utility might target programs with a wide gap between costs and savings, and not pursue programs with lower benefit/cost ratios. To address this problem, New England Electric proposed a two-part shared savings mechanism. In addition to a 10 percent share of net benefits (an Efficiency Incentive), it would also get a 5 percent share of gross benefits or total avoided cost (a Maximizing Incentive). This has been allowed for the Company's Narragansett Electric and Granite State Electric subsidiaries by the Rhode Island and New Hampshire commissions, respectively. In California, San Diego Gas & Electric has a similar scheme. Some utilities are only allowed a share of net benefits over some minimum level.

Q. PLEASE DISCUSS ALTERNATIVE MECHANISMS.

A. A positive incentive can be created by a **bounty** mechanism, which can be an award of a fixed dollar amount for each kW or kWh saved. A variant of a bounty mechanism is a **premium or discount on the authorized rate of return** on common equity. For example, in Colorado Docket No. 91A-480EG the Commission set an incentive/penalty of one basis point for each percentage deviation from the targeted amount, with a dead band of plus/minus 10 percent and a limit of 100 basis points (1 percentage point) more than or less than the authorized return.

Q. ARE THERE OTHER ALTERNATIVES?

A. Yes. A simple alternative is the inclusion of DSM investments in rate base with an allowance of a higher rate of return on those DSM investments than on supply-side investments. For example, there could be a 200-basis-point (2 percentage point) premium on the common equity component of DSM investments.

Q. ARE THERE POSSIBLE DISADVANTAGES TO BONUS OR BOUNTY MECHANISMS?

A. Yes. Bonus and bounty mechanisms that are based on a utility's level of investment in DSM may reward expenditures of money, rather than results. In addition, bonus and bounty mechanisms that are based on savings do not necessarily encourage that the maximum DSM value be pursued. Incentives should not encourage expenditure as such, but the creation of the value with the minimum expenditure. To address the danger that costs might not be adequately controlled, a separate mechanism could be provided for cost control by developing target costs for the packages of conservation programs included in the target DSM savings. However, the addition of this feature makes a bounty scheme more complicated, and still does not address the need to reward savings achievements.

Q. ARE LIMITS SOMETIMES PLACED ON THE AMOUNT OF INCENTIVE EARNINGS A UTILITY CAN RECEIVE?

A. Yes. Some schemes, indeed most, place a cap on the incentive. The most common mechanism is a limit on the additional return on common equity provided by the mechanism over and above the allowed rate of return. The cap is usually in the range of 50 to 100 basis points (0.5 to 1.0 percentage point), applied to the entire common equity of the company. The cap can alternatively be a dollar amount or a limit on the premium earned on the ratebased DSM investment, for example 200 basis points (2 percentage points). Where there is a penalty for under-performance, there may be a limit on the amount of that penalty.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ALTERNATIVE TYPES OF INCENTIVE MECHANISMS?

A. Most of the incentive mechanisms recently put in place fall into the categories of shared savings or adjustment to return on equity. I generally favor shared savings on the grounds that it provides the utility with the incentives to plan for and implement the appropriate level of DSM. I agree with the California Energy Commission which summarized its position as follows:

> Under the shared savings approach, utilities earn a percentage of the difference between the program costs and the value of the avoided energy supply. Rate of return incentives (which are the other kind available to California utilities) are based on a percentage of dollars spent. Incentives based on a value provide a more effective mechanism than incentives to spend money.

(1992-1993 *California Energy Plan*, pages 40-41.)

Q. DO YOU OPPOSE THE USE OF BOUNTY MECHANISMS?

A. No. I am not averse to the inclusion of some bounty features along with shared savings. But I believe the primary emphasis should be on shared savings.

<u>DSM Incentive Mechanisms Proposed in Pennsylvania</u>

Q. HAVE ANY DSM INCENTIVE MECHANISM BEEN PROPOSED IN THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes, in an Order entered October 7, 1991, the Pennsylvania Public Utility Commission discussed a proposed Energy Efficiency Adjustment (EEA) which contained a performance-based incentive that would allow utilities to retain a portion of the projected net benefits of pre-approved DSM programs. This shared-savings mechanism would apply only to programs which 1) produce viable alternatives to traditional supply options, 2) have a definite resource value which could be readily converted into energy and demand savings, and 3) provide on-peak savings, or a combination of on-peak and off-peak savings.

In 1993, a revised shared-savings DSM incentive mechanism was proposed by the electric utilities as part of an EEA. The revised incentive provided that off-peak demand or energy savings should also be eligible for shared savings incentives because all savings are valuable. In its 1993 DSM Cost Recovery Order, the Public Utility Commission ordered that the proposed EEAs be replaced by a different surcharge mechanism, referred to as the Demand Side Cost Rate (DSCR). The DSCR included a direct cost recovery component for DSM expenditures, as well as a DSM incentive component that was to be based on an (unspecified) off-system sales price multiplied by the number of kWh sales. The utilities would have to verify, in an annual proceeding, the kWh savings of DSM programs.

The Order provided electric utilities with the option to recover the rewards of the DSM incentive either through the surcharge mechanism (the DSCR) or in base rate proceedings.

Q. PLEASE ADDRESS THE EXTENT TO WHICH DSM INCENTIVES CAN BE CALCULATED USING OFF-SYSTEM SALES TO VALUE THE INCENTIVE PAYMENTS, AS PROPOSED BY THE COMMISSION'S APRIL, 1994 ORDER.

A. The average price of off-system sales can serve in an incentive mechanism as a measure of the near-term value of power (i.e., short-run marginal energy costs). Alternatively, bearing in mind the Commission's treatment of this issue, the average of the PJM pool's hourly marginal energy cost for a designated period could be used for a PJM company, like PP&L, and for a non-PJM company to the extent the Commission concluded that the value of power to that company approximated PJM's. In addition, a value for avoided capacity should be added to the PJM marginal energy cost.

Q. WHAT IS THE CURRENT STATUS OF THE DEMAND SIDE COST RATE PROPOSED IN THE 1993 DSM COST RECOVERY ORDER?

A. As I understand it, neither the DSCR, nor any DSM incentives, are currently in place in Pennsylvania as the result of the appeal I cited above. I am proceeding on the assumption that the Commonwealth Court's vacating the PUC's April 7, 1994 Order reversed the calculation for DSM incentives in the form of a surcharge mechanism (i.e. in the DSCR), and that the recovery of DSM incentives can only be lawfully addressed in base rate proceedings.

Q. HAS PP&L ADDRESSED THE ISSUE OF DSM INCENTIVES IN ITS CURRENT BASE RATE FILING?

A. No, it has not.

Q. DO YOU SUPPORT THE PROVISION FOR RECOVERY OF DSM INCENTIVES IN THE FORM OF A SURCHARGE MECHANISM?

A. Yes, I believe that a surcharge provides the most immediate and appropriate recovery mechanism. Postponing the recovery of benefits under a DSM incentive plan ignores the need for an innovative mechanism to encourage utilities like PP&L to pursue additional DSM. I believe the incentive will be more effective if the delay in providing a reward for good DSM performance is minimized. I recommend that the Commission provide PP&L and other electric utilities the option to recover DSM incentives in the form of a surcharge mechanism, to the extent that it is ultimately allowed by the Pennsylvania Supreme Court.

Q. ARE THERE OTHER OPTIONS FOR RECOVERING DSM INCENTIVES?

A. Yes. DSM financial incentives can be recovered through adjustments to base rates. In this case, the amount of the incentive would be based on the amount of DSM savings in the test year. This approach has a significant disadvantage because of the time lag between base rate cases, and because the level of DSM savings may vary significantly from the test year levels. As a result, I recommend that this approach only be adopted if surcharges, or other more timely approaches, are not possible.

Q. HOW SHOULD SAVINGS ESTIMATES BE DETERMINED FOR PURPOSES OF CALCULATING THE DSM INCENTIVE?

A. For purposes of calculating a DSM incentive, and more fundamentally, for calculating whether the programs have positive cost/benefit, it is necessary to measure the savings with reasonable accuracy. Here, I have the following recommendations:

- DSM programs should have a substantial measurement and evaluation component.

- Measured savings data should be used to estimate savings when available.

- If engineering estimates are used initially, measured data should be used to supplement and/or replace this data when such data become available.

4. DSM: RECOVERY OF NET LOST REVENUES

Q. PLEASE DESCRIBE THE ROLE OF NET LOST REVENUE RECOVERY IN MAKING DSM A VIABLE RESOURCE OPTION FOR ELECTRIC UTILITIES.

A. A regulatory barrier exists in many states to utility investment in demand-side management. Under traditional regulation and rate design, utility sales and revenues are linked directly with utility profits, such that a utility's revenues and profits increase whenever it sells an additional kilowatt-hour of energy, or decrease whenever a kWh is conserved through DSM. It is by now widely accepted that utilities are unlikely to undertake aggressive DSM programs unless they are somehow compensated for the lost revenues that result from lower sales. In 1988, the National Association of Regulatory Commissioners urged PUCs to adopt ratemaking policies that would make DSM at least as profitable as supply-side investments. Regulatory commissions in at least 21 states have established various mechanisms to allow utilities to recover lost revenues from DSM.

The preferred approach to lost revenue recovery from DSM programs among utilities and regulators is net lost revenue adjustment (NLRA) mechanisms. NLRA mechanisms allow utilities to recover only the fixed cost portion of lost revenues, and not the variable cost (e.g. fuel costs), since the utility does not incur this cost when sales fall due to DSM -- hence, the recovery of net lost revenues.

Q. PLEASE BRIEFLY DESCRIBE THE DIFFERENT TYPES OF NLRA MECHANISMS SUPPORTED BY COMMISSIONS THROUGHOUT THE U.S..

A. There are three basic types of NLRA mechanisms: a prospective surcharge; a retrospective surcharge; and a deferred account. The surcharge mechanisms are reflected as rate charges on customer bills and typically represent one component of an overall DSM surcharge. A prospective surcharge recovers revenues lost as a result of current year DSM program activities, such that the utility recovers net losses as the losses are incurred. Under this approach, utilities file a forecast of DSM savings and associated net lost revenues for the upcoming program year, and typically submit an annual filing to the commission which, after approval, serves as the basis for an

NLRA surcharge. The retrospective surcharge mechanism differs from the prospective surcharge in that it is designed to recover revenues lost from DSM activity in a previous year. Under same surcharge mechanisms, net lost revenues due to DSM savings estimates are later reconciled with DSM measurement and evaluation results.

Under the deferred account approach, net lost revenues estimates are tracked through an account, and receive authorization for recovery in the utility's base rate case according to results of DSM measurement and evaluation.

Q. HAVE NLRA MECHANISMS BEEN SUCCESSFULLY IMPLEMENTED BY UTILITIES IN THE STATES?

A. Yes. A number of states have successfully implemented NLRA mechanisms. I have concluded that NLRA is a feasible approach to countering the DSM disincentive. I commend to the Commission a recent study of the Oak Ridge National Laboratory (ORNL), *Assessment of Net Lost Revenue Adjustment Mechanisms for Utility DSM Programs*, January 1995. There are several conditions required for effective NLRA implementation. The most prominent of these conditions are 1) avoiding a strict ex post approach to DSM measurement; 2) involving stakeholders in the process; and 3) setting conditions for lost revenue recovery related directly to DSM program operation and performance.

Q. PLEASE DISCUSS MORE SPECIFICALLY WHY A STRICT EX POST APPROACH TO DSM MEASUREMENT SHOULD BE AVOIDED IF AN EFFECTIVE NLRA MECHANISM IS TO BE IMPLEMENTED.

A. A state's approach to DSM measurement is the most important indication of implementation success of a NLRA. State commissions that do not rely on a strict ex post approach to verify DSM savings are apparently satisfied with their NLRA mechanisms, while state commissions with a strict ex post approach to DSM measurement are apparently less satisfied.

A strict ex post approach attempts to ensure that utilities are compensated only for net lost revenues that can be accurately measured. Net lost revenue recovery is based on after-the-fact measurements of DSM actual impacts that are determined from impact evaluations which focus on the statistical analysis of customer energy use data. The difficulty of this approach lies in the <u>retrospective</u> reconciliation of total program savings, which involves verifying both program participation and unit savings. Unit savings are more difficult and expensive to verify, and increase both the administrative and technical burden of regulatory and utility staff, especially when these savings are tracked over time as required under a deferred account approach.

A less burdensome approach is to limit retrospective reconciliation to program participation, where a utility reconciles projected to observed program participation levels. Because participation levels are generally straightforward to track, they are easy to compare to projected participation. Furthermore, this reconciliation process can be performed shortly after the end of each program year.

Q. DOES THE PENNSYLVANIA COMMISSION REQUIRE UTILITIES TO RECOVER LOST REVENUES USING A STRICT EX POST APPROACH TO DSM MEASUREMENT?

A. As I interpret it for the purpose of my recommendations here, the PUC's 1993 DSM Cost Recovery Order provided that utilities recover net lost revenues caused by DSM through a base rate proceeding using a deferred account to track losses between rate cases, and that DSM savings be measured using a strict ex post approach. The Commission's order also included a provision whereby a utility could petition for special rate relief should it be able to justify inclusion of net lost revenues in its annual DSM balancing account.

The Commonwealth Court later remanded the PUC's order on the issue of net lost revenue recovery. I am not aware of any net lost revenue recovery mechanism in place.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING ITS PREVIOUS RULING THAT REQUIRES UTILITIES TO USE A STRICT EX POST RECONCILIATION METHOD TO DETERMINE NET LOST REVENUES?

A. I recommend that the Commission approve in this case a verification process based on program participation, and not on total energy and demand savings, for the reasons discussed above.

Q. DO YOU SUPPORT THE COMMISSION'S DECISION (ALBEIT A DECISION NOT YET IN EFFECT) THAT REQUIRES UTILITIES TO USE A DEFERRED ACCOUNT APPROACH FOR RECOVERY OF NET LOST REVENUES?

A. My preference is a retrospective surcharge mechanism, included as part of an overall DSM surcharge. Surcharge recovery of net lost revenues comports with the changes in the electric utility industry that have occurred in Pennsylvania since the Commission issued its December 1993 DSM Cost Recovery Order. With utility managements around the country responding to unknown "competitive" changes by cutting staff across the board and DSM programs in particular, it becomes critical that PP&L perceive an immediate opportunity to be made whole for successful DSM.

However, if the Commission holds to its earlier position requiring base rate recovery through a deferred account, then it should allow PP&L to be eligible for "special rate relief", in the form of annual recovery, if PP&L is able to meet certain performance target conditions. An example of a performance target condition would be to base the level of net lost revenue recovery on specific percentages of the stated savings goals in the utility's pre-approved DSM Plan. Indeed, to the extent that the Commission is barred from providing incentives through annual retrospective proceedings, it is even more important to provide utilities with timely and predictable recovery of net lost revenues and, of course, direct costs.

Q. DO YOU RECOMMEND A SPECIFIC ELIGIBILITY CRITERIA BY WHICH PP&L CAN APPLY FOR ANNUAL RECOVERY OF NET LOST REVENUES?

A. Yes. I recommend that the Commission grant PP&L annual recovery of net lost revenues if the Company meets 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan. The utility would have to allege that it had met this goal, offering sworn testimony in its application. That would qualify it for a hearing. Then it would have to prove its allegations in a contested proceeding, with the opportunity for stakeholders to review all relevant information and cross examine. Upon a Commission finding that PP&L had proved it had met the 60 percent floor the annual recovery would be authorized.

Q. HOW ELSE MIGHT PERFORMANCE TARGET CONDITIONS BE USED AS A BASIS FOR RECOVERY OF NET LOST REVENUES?

A. Performance target conditions can also be used as a floor for recovery. A benchmark level should be set requiring that PP&L meet a specific percentage of its overall DSM savings goal in order for it to recover <u>any</u> net lost revenues for that program year. I recommend a level of 60 percent be required by the Commission.

Q. HAS THE COMMISSION RECOMMENDED A METHODOLOGY FOR CALCULATION OF NET LOST REVENUES?

A. No. In its December 1993 DSM Cost Recovery Order, the Commission stated that it did not deem it appropriate or necessary for it to address, with any specificity, the methodologies or procedures for calculating net lost revenues, but that such issues should be resolved during the DSM program evaluation process.

Q. DO YOU RECOMMEND THAT THE COMMISSION RESOLVE THIS ISSUE IN THIS DOCKET?

A. Yes. The Commission should establish a proper methodology for calculation of net lost revenues at this time, even if it opens a generic remand proceeding in which this issue can be addressed.

Q. PLEASE DESCRIBE A METHODOLOGY FOR CALCULATING NET LOST REVENUES.

A. While there are a number of specific methods used to estimate net lost revenues from DSM programs, there is a general procedure common to most methods. Several basic steps are required to calculate net lost revenues.

First, the utility must establish a protocol, to be approved by the Commission, for measuring the annual savings (in kWhs and kWs) for each of the DSM measures. A standard approach is to estimate the energy and demand savings for each measure (the unit savings) and then multiply these per unit savings estimates by the number of participants (or DSM measures) in that program year. In order to perform this first step of the calculation, the utility must have demonstrated the cost-effectiveness, based on the Total Resource Cost Test, of the DSM programs for which it wishes to recover lost revenues.

Second, the utility must estimate the fixed cost component of retail rates. This is typically done by subtracting the short-run variable cost for each rate class from the retail energy rates and demand charges assigned to each rate class.

Third, for each rate class, the fixed cost rate for energy is multiplied by the total annual energy savings, and likewise, the fixed cost for demand is multiplied by the total demand savings. The sum of these products provides a total net lost revenue for each rate class. The sum over all rate classes is an estimate of the utility's total net lost revenues from DSM program activities in that year to be applied either to a surcharge mechanism or added to a deferred account. In Sierra Club Exhibit No. 1C, I provide a formula for how to calculate net lost revenues based on my recommended methodology for reconciling DSM savings.

5. RATE DESIGN & SYSTEM RELIABILITY: DISCOUNT RATES

Q. PLEASE DESCRIBE BRIEFLY THE PRINCIPLES GOVERNING THE DEVELOPMENT AND USE OF WHAT ARE GENERALLY CALLED "DISCOUNT RATES".

A. Discount rates, sometimes referred to as flexible or "flex" rates, are a central issue of concern to public utility regulators. Utilities are increasingly looking for ways to lower energy prices to high load factor customers who threaten to leave the system either by means of self-generation or simply by folding their operations in the utility's service territory. One way to retain these contestable customers is for utilities to offer discount, or load retention rates. Such rates can lead to rate inequity, where non-discount customers often bear the burden of subsidizing the lost revenues that result from the discount rates.

The design of discount rates departs from traditional cost allocation in an embedded cost of service study. Absent any consideration of discount rates, rates would simply be designed to meet class revenue requirements based on average embedded costs. The problem with discount rates is that they are based on designs that set long-run marginal cost as a floor price. If long-run marginal cost is below the average embedded cost, the discount rate will often not cover the class revenue requirement set for the class receiving the discount rate. In order to justify a discount rate which does not produce the full class revenue requirement, the utility must typically show that other rate classes somehow benefit from the discount rate.

Q. DO YOU PROPOSE TO TESTIFY FOR OR AGAINST THE USE OF DISCOUNT OR RETENTION RATES?

A. Neither. However, if discount rates exist, I am of the opinion that they are only appropriate to the extent that they provide a least cost response to potential loss of a customer either to uneconomic bypass, or to cessation of or curtailment of business activity in the utility's service territory.

Q. PLEASE EXPLAIN WHY DISCOUNT RATES, IN AND OF THEMSELVES, DO NOT PROVIDE A LEAST COST RESPONSE TO RETAINING CONTESTABLE CUSTOMERS.

A. Discount rates are often excessively costly, and require that a utility shift costs to non-discount customer classes. This can create price discrimination where core customers, such as residential and small commercial customers, effectively subsidize the cost of energy service for those customers that receive special discounts. Utilities generally argue that core customers are "better off" under this scenario than under the alternative in which a contested customer leaves the system and core customers bear the burden of paying the associated lost revenues. (This utility argument, of course, assumes that core customers must bear all or part of this burden).

The truth to this argument depends on the extent to which DSM measures have been undertaken to reduce energy costs for the contestable customer. This is due, in great part, to the fact that the industrial customer seeking the discount is focused on reducing its **bill**, not its rates per se. The rate discount is merely a means to achieve the end of the lowered energy bill.

If little or no DSM measures have been put in place at the facility of the prospective discount customer, an opportunity exists to reduce not only the customer's energy bills, but also the level of the discount rate and the resulting costs to the utility and its other customers.

Discount rates, in and of themselves, do not provide a least cost option, and unless properly structured and conditioned are therefore uneconomical and represent bad policy. Cost-effective DSM investments can substantially reduce, or even eliminate, the need for utilities to enter into costly long-term agreements that often subsidize uneconomic use of energy services.

Q. PLEASE DESCRIBE A LEAST COST APPROACH TO DETERMINING DISCOUNT RATES.

A. A least cost approach should require that a discount rate reflect the cost savings potential of appropriate levels of cost-effective DSM investment, based on a certified energy audit for a contestable customer.

Q. HOW MIGHT THE DISCOUNT RATE BE NEGOTIATED TO REFLECT THE AMOUNT OF FORECASTED DSM SAVINGS OR ANTICIPATED BILL IMPACT TO THE DISCOUNT CUSTOMER?

A. One possible way to set the discount rate would be to scale the rate back according to the percentage decrease, or a portion of that decrease, that cost-effective DSM could contribute to the customer's anticipated bill.

Here is a theoretical example: A customer seeks a "rate" discount of 20 percent -- really a 20% discount in the energy bill. A certified energy audit shows that DSM can reduce the customer's bill by 10 percent. The utility offers to match a 10 percent rate discount with the DSM savings impact, plus an additional 5 percent rate discount to serve as an added incentive for the customer to participate. The effective discount to the customer is 25 percent, a combination of the energy savings due to DSM and the utility's discount. This is even more than what the customer had originally requested.

The cost to the utility is lower, at 15 percent, than what it would have been had the utility granted the 20 percent discount originally requested by the customer.

Please keep in mind that these figures are offered merely as an illustrative example, and that for any particular customer, or even the average customer, a negotiation might produce different numbers. Indeed, in some cases all the bill savings that a customer seeks could come from energy efficiency by itself. Also, my example does not specify who provides the DSM services. While a large industrial customer has the infrastructure and financing ability to secure its own DSM contractors, a "competitive" utility might see this as a business opportunity -- to provide its dissatisfied customer with premium energy services.

There are other benefits to this approach -- economic development benefits. It is well-understood that DSM's economic multiplier effect is greater than that for utility payments. So, dollars that flow into DSM measures, and ultimately, into local customers' pockets, generate more economic activity than prior rate payments. The investment in DSM for this customer will have an immediate positive impact on the local economy, a function of the extent to which local services and materials go into the energy efficiency "fixes" at the customer's premises.

Q. DO ANY STATE COMMISSIONS REQUIRE THAT DSM MEASURES BE IMPLEMENTED IN ORDER FOR CUSTOMERS TO RECEIVE SPECIAL DISCOUNT RATES?

A. Yes. The New York Public Service Commission ordered in Case 93-M-0229 that utilities in the state, including Rochester Gas & Electric (RG&E), Niagara Mohawk, and New York State Electric & Gas (NYSE&G), include energy audits as an eligibility requirement for prospective discount rate customers. The PSC's Order requires that a utility first demonstrate that the prospective discount customer has a competitive alternative to purchase electricity from the utility, where the alternative may be for the customer to cogenerate or to relocate outside the utility's service territory.

Currently, there are about 25 contracts in place in New York that are based on this type of discount rate. These include Niagara Mohawk, with 17 contracts, NYSE&G with 5, and RG&E with two.

Q. WHAT OTHER PRINCIPLES WERE ESTABLISHED BY THE NY PSC FOR ITS FLEXIBLE DISCOUNT RATE PROGRAM?

A. In Sierra Club Exhibit No. 1D, page 1, I have included a copy of the PSC's nine Guidelines on Flexible Rates. Pages 2 through 4 of this Exhibit include descriptions of eligibility requirements for flexible rates for NYSE&G, NiMo, and RG&E.

Once these requirements have been fulfilled, the utility has the ability to negotiate a discount rate based on the results of the energy audit.

Q. HAVE THE FLEXIBLE DISCOUNT RATE PROGRAMS IN NEW YORK BEEN SUCCESSFUL?

A. Yes. One example is a case where an RG&E customer, University of Rochester, threatened to leave the system and obtain its electricity through cogeneration. However, through the state's flexible rate discount program, an energy audit was performed, the results of which coupled a DSM investment project to a negotiated discount rate in the utility's retention contract with the U. of Rochester. The University agreed to stay on as a customer for an additional six years.

Q. WHAT IS YOUR RECOMMENDATION TO THE PENNSYLVANIA COMMISSION WITH RESPECT TO HOW PP&L MIGHT PROVIDE A LEAST COST APPROACH TO ESTABLISHING DISCOUNT RATES?

A. I recommend that the Commission adopt a program for large business customers similar to that adopted by the New York Commission. Specifically, customers should be required, before they are given a discount rate to:

- provide the results of a comprehensive energy audit, by professionally certified auditors;
- identify and install all measures that are cost-effective based on the Total Resource Cost Test and that have a reasonable payback period. I recommend that a simple payback period of 5 years be used as the criterion.

The certification can be by any appropriate energy efficiency organization. The purpose of the certification requirement is to insure that the assessment of the customer's capabilities is by a knowledgeable, qualified professional who is likely to produce an unbiased report.

Q. WHAT OTHER PROVISIONS SHOULD THE COMMISSION REQUIRE IN ORDER FOR PP&L TO APPROPRIATELY DETERMINE DISCOUNT RATES?

A. One critical issue that I have not yet addressed is the importance of determining who should bear the burden of revenues lost through the discounts. I strongly recommend that all revenues lost through discounts, or at least a substantial portion, be borne by the stockholders for the full term of a discount. I have two reasons: First, this would allow for a more equitable sharing of risk between stockholders and other customers. Second, it would provide the utility with the incentive to require that prospective discount customers undertake energy audits and the installation of cost-effective measures in order to minimize the potential lost revenues that result from discounted rates.

I also recommend that the Commission require, in cases where lost revenues due to discounted rates are not entirely borne by the shareholders, that utilities ensure that all customers are provided access to cost-effective DSM measures. This is especially critical for bill-sensitive customers such as low-income customers, who would be more sensitive to price increases due to discount rates. By providing DSM savings for these customers, the utility effectively minimizes the bill impacts of the discounted rate.

Q. HOW COULD THIS REQUIREMENT BE INCLUDED IN PP&L'S TARIFFS?

A. The DSM requirement should simply be included in the terms and conditions for any discounted rate the Commission authorizes.

6. RATE DESIGN & SYSTEM RELIABILITY: SYSTEM BENEFITS CHARGE

Q. IS THERE ANYTHING THAT THE COMMISSION CAN DO IN THIS RATE CASE TO PREPARE FOR INCREASING LEVELS OF COMPETITION IN THE ELECTRIC UTILITY INDUSTRY?

A. Yes. The Commission can provide for cost recovery for potentially stranded benefits such as low-income energy efficiency programs. This can also include DSM programs and cost-effective renewable energy acquisitions to the extent that their initial cost streams exceed short-term commodity costs. Cost recovery of these stranded benefits can be done through a system benefits charge in retail rates for the distribution of electricity.

Q. WHAT ARE STRANDED COSTS?

A. With the prospect of increasing competition, perhaps to include direct access, utilities are concerned that various investments made in the past (for example, the costs of constructing baseload power plants) will not be recoverable. To the extent that current prices for electricity exceed "market value" the costs may be seen as "uneconomic" and potentially stranded, depending upon future developments. It is not my intention to define or discuss stranded costs here. Rather, I note simply that the concept has received a great deal of attention recently, and that there is an analogous concept of "stranded benefits."

Q. PLEASE EXPLAIN HOW COMPETITION CAN LEAD TO STRANDED BENEFITS.

A. Utilities are increasingly concerned about making long-term investments of all kinds, including those in electricity-saving and renewable energy initiatives. The result is a growing body of "stranded benefits" from what would have been highly cost-effective investments. The existence of the stranded benefits has been recognized by NARUC in a resolution passed unanimously at its November 1994 meeting. The NARUC resolution is provided here as Sierra Club Exhibit No. 1E.

Q. WHY IS IT IMPORTANT TO COLLECT CERTAIN STRANDED COSTS THROUGH A SYSTEM BENEFITS CHARGE?

A. In an environment in which utilities are concerned about uncertainty, competition, and stranded costs they are sometimes reluctant to pursue programs that could increase the magnitude of stranded costs, no matter how worthy the programs are and how comparatively tiny the investments. At the same time, DSM and low income programs continue to be important for cost and equity reasons. In this environment it is important for the Commission to clarify that costs associated with cost-effective DSM programs pursued in the public interest will not be "stranded" if some customers decide to and are allowed to leave the system. This prepares for the provision of electricity service at low cost while maintaining important programs (e.g., DSM and low income) if and when competition materializes.

Q. ARE YOU ADVOCATING INCREASED COMPETITION, INDUSTRY RESTRUCTURING OR RETAIL WHEELING?

A. No. Regardless of what should happen with competition, or what eventually does happen, there is currently a high level of uncertainty which itself is sometimes taken as a reason to cut back important utility programs. My proposal for a system benefits charge is a means of preserving these programs in the current uncertain environment, and in the future, whatever form it takes.

Q. HOW DOES YOUR PROPOSED SYSTEM BENEFITS CHARGE COMPARE WITH THE COMPANY'S PROPOSAL TO RAISE THE CUSTOMER CHARGE?

A. My proposal is volumetrically based, not customer based. But it accomplishes one of the same purposes, namely a tendency toward certainty of revenues.

Q. WOULD THE SYSTEM BENEFITS CHARGE INCREASE THE RATES SET IN THIS CASE?

A. No. It would not change rates at all. It is merely a reclassification of costs intended to provide increased assurance of recovery. If, in the future, the utility de-integrates into functional areas, the system benefits charge would be associated with the distribution function. All distribution customers, regardless of where they purchase their generation, or whether they self-generate, would be required to pay the system benefits charge.

Q. WOULD THE SYSTEM BENEFITS CHARGE CHANGE COST ALLOCATION OR DSM COST RECOVERY?

A. No, the system benefits charge does not change the allocation of these costs to customer classes, nor does it change the pattern of cost recovery over time.

Q. HAS THIS SORT OF CHARGE BEEN IMPLEMENTED ELSEWHERE?

A. Yes. Washington Water Power proposed a usage-based distribution charge for recovery of its DSM investments. The proposal was approved by the Washington Utilities and Transportation Commission.

Q. WHY SHOULD THE COMMISSION IMPLEMENT A SYSTEM BENEFITS CHARGE NOW?

A. It is important at this point in time for the Commission to reduce the uncertainty and confusion regarding competition and stranded costs, and encourage utilities to provide programs that are sensible in terms of cost, equity and long-term considerations. Reliance solely upon competitive forces to determine electricity supply could, if done thoughtlessly, overemphasize near-term prices to the detriment of other legitimate electric system policy objectives.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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TELLUS INSTITUTE
for Resource and Environmental Strategies

Electricity Program

Objective

The Electricity Program provides technical and policy advice to public agencies and private organizations involved in planning and regulation of electric utilities. We provide rigorous quantitative analyses of the environmental, economic and equity impacts of developing and using electric energy. Our staff conducts long-term research projects and participate in dozens of state and federal regulatory proceedings each year.

Scope

The Electricity Program addresses the following aspects of electric utility planning and policy:

- Integrated Resource Planning
- Environmental Impact Assessment
- Power Plant Review
- Renewable Energy Evaluation
- Demand-Side Management Planning
- Ratemaking, Incentives and Industry Structure

Integrated Resource Planning

Tellus has been a leading proponent of integrated resource planning (IRP) throughout the U.S. We have been active in developing IRP methodologies aimed at meeting energy demands at the lowest cost to society, including the environmental costs of different resources. Our policy analyses account for the rapidly changing regulatory and institutional forces in the electricity industry. Tellus has extensive experience with the following aspects of IRP:

- Load forecasting
- Avoided cost estimation
- Integration of supply and demand resources
- System planning, reliability & dispatch analyses
- Competitive power procurement
- Transmission and distribution planning
- Risk assessment and avoidance

We have formulated IRP rules, developed comprehensive integrated resource plans, and reviewed utility IRP filings. Recent projects include:

- Advice to the Board of Directors of the Tennessee Valley Authority on the development of TVA's integrated resource plan as required in the Energy Policy Act of 1992.

- Work with the Kansas Corporation Commission to develop the state's formal proposed IRP rule, one of the first to cover both electric and natural gas utilities in a consistent manner. We also worked for the Colorado Office of Energy Conservation and the New Mexico Office of Attorney General on similar IRP rule making projects.

- Review of concepts and approaches to electric IRP in North America, including case studies and critical analyses of the IRP activities of seven major electric utilities. The work was sponsored by a collaborative including Hydro-Québec and numerous provincial groups and associations representing the public interest.

- A comprehensive, least-cost electric IRP for the Vermont Department of Public Service, including position papers on key IRP issues. Tellus has reviewed and made recommendations to state agencies on IRPs from many utilities, including Potomac Electric Power Company, Public Service Company of Colorado, PacifiCorp, Southern Company, Union Electric, and many others.

- Development of a handbook for calculating electric system avoided costs. This project is being funded by the EPA Office of Air and Radiation and DOE Office of Energy Efficiency and Renewable Energy.

- Economic analysis of the costs and benefits of a proposed 345-kv transmission line in Pennsylvania for the Office of Consumer Advocate, complementing a previous Tellus study of the line's potential EMF (electromagnetic field) health and ecological impacts.

Environmental Impact Assessment

Tellus has extensive experience in analyzing the environmental impacts of electricity resources. We have assessed environmental regulations, reviewed and developed protocols for reflecting environmental externalities in resource planning, and analyzed the Clean Air Act Amendments and associated utility compliance plans. Recent projects include:

- Assistance to the Vermont Department of Public Service in a docket to develop an environmental externalities rule for the state's utilities.

- Extensive work on integrated resource management efforts in Massachusetts with the Division of Energy Resources. Tellus developed environmental externality values which were adopted by the Department of Public Utilities, and have received national attention.

- Evaluation and critique of environmental issues in the Southern Company's IRP, including their Clean Air Act compliance plans. Tellus has completed similar compliance reviews of Cincinnati Gas & Electric, Dayton Power & Light, and Centerior Energy, for the Ohio Consumers Counsel.

- For the U.S. EPA, analysis of opportunities for electric power systems to reduce their greenhouse gas emissions efficiently by anticipating climate change policy.

- For the Empire State Electric Energy Research Corporation (ESEERCO), development of a computerized model to estimate site-specific environmental damages from power plants in New York state.

Power Plant Review

Tellus has extensive experience analyzing and reviewing the economic and environmental impacts of specific utility power plant decisions, including:

- New power plant construction
- Plant retirement
- Major capital additions
- Plant life extension
- Relicensing
- Repowering
- Supply-side efficiency standards

Recent projects include:

- Review of the environmental and economic impacts of on-site high-level radioactive waste storage facilities at the Point Beach nuclear plant for the Wisconsin Citizens Utility Board.

- Review of the environmental impacts of repowering the Bergen Station on behalf of New Jersey's Division of Rate Counsel, and review the economic and ratepayer impacts of retiring coal-fired generating units in Pennsylvania for the Office of Consumer Advocate.

- For the Illinois Citizens Utility Board, calculation of the costs and benefits associated with three of Commonwealth Edison's recent nuclear additions.

- For the staff of the Maryland Public Service Commission, development of statistically based targets for the state's power plant performance program.

- Analysis of nuclear power plant decommissioning and radioactive waste issues on behalf of the Arizona Residential Utility Consumer Office, the Vermont Department of Public Service, the Wisconsin Citizens Utility Board, and others.

Renewable Energy Evaluation

Tellus provides technical and policy assistance to help develop renewable energy and alternative energy resource strategies. We have estimated the technical and market potential for renewables, analyzed the integration of renewable resources into system dispatch and planning, and provided policy recommendations for state energy plans. Recent projects include:

- One of six U.S. DOE "innovative IRP grants" to analyze the integration of wind and biomass generation into electric power system planning and operation.

- For the Massachusetts Division of Energy Resources, assessment of the technical potential for the state's renewable resources, and development of the state policy options.

- *America's Energy Choices*, a national energy strategy emphasizing conservation and renewables, developed jointly with the Union of Concerned Scientists, the Alliance to Save Energy, the American Council for an Energy-efficient Economy, and the Natural Resources Defense Council

Demand-Side Management Planning

The efficient use of energy resources is central to IRP. We emphasize DSM both as a significant priority for utility planning, and for the development of regional and national energy policy. Recent projects include:

- For the Colorado Office of Energy Conservation, testimony critiquing utility DSM methods and assumptions, including assessment of rate and environmental impacts.

- For the New Jersey Department of Public Advocate, review of DSM as an alternative to plant repowering for Public Service Electric & Gas.

- For the Arkansas Public Service Commission, participation in a collaborative process to design a DSM plan for Entergy/Arkansas Power & Light.

- For the Boston Edison Company Settlement Board, performing a review of the non-price benefits of electric utility demand-side management. This includes environmental benefits associated with avoiding power supply sources, as well as employment impacts, resource depletion considerations, low-income customer considerations, spillover and market transformation effects, and others.

Databases and Models

Tellus expertise includes the development and application of computerized databases and planning models, addressing a wide range of energy issues. Recent projects include:

- For the Energy Foundation, development of a database of costs, ages, efficiency levels, and other characteristic of nuclear and fossil-fueled power plants throughout the U.S., to help assess retirement and repowering options.

- Compilation and analysis of a database of more than 100 engineering estimates of nuclear power plant decommissioning cost.

- *ECO*™ , the Tellus energy conservation options model, can assist planners in identifying the cost-effective DSM measures and programs. It has been used in DSM planning projects for municipal electric systems, gas utilities, and governmental agencies in the U.S. and abroad.

Ratemaking, Incentives and Industry Structure

Ratemaking

Tellus has an extensive body of experience in electric utility cost of service, cost allocation, and rate design analysis. Staff promote ratemaking based on cost, and attempt to meet objectives such as equity and efficiency.

- Since the firm was founded in 1976, Tellus staff have testified in over 130 utility ratemaking proceedings for public utility commissions, consumer advocates, and other public-sector agencies in over 35 states.

- Tellus recently completed a white paper for NARUC, the National Association of Regulatory Commissioners, describing how rate design can be aligned with the principles of Integrated Resource Planning (IRP).

- On behalf of the Rhode Island Division of Public Utilities and Carriers, Tellus provided comments on the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) on recovery of stranded costs. Tellus reflected Rhode Island's concern about the impact of competition in general and stranded costs on the market for wholesale electricity in Rhode Island.

- The Tennessee Valley Authority's Board of Directors commissioned Tellus to conduct an independent, confidential study on the implications of the competitive forces that TVA might face both in the short- and long-term. Tellus identified, framed, and analyzed key issues within the context of TVA's unique operating conditions, and performed a quantitative analysis of the competitive threat to TVA based on projections of TVA rates and the market price of electricity in the TVA region. Tellus has also assisted the TVA in developing comments to the FERC's Notice of Proposed Rulemaking on recovery of stranded costs.

- On behalf of the Arkansas Public Service Commission, Tellus submitted testimony on IRP for Arkansas Power and Light Company. The testimony explained why competition and IRP are not inherently incompatible, but rather that competition can be supplemented by IRP policies to create a more efficient electricity market.

Incentive Regulation

To remedy certain disincentives contained in traditional utility ratemaking, state commissions are increasing their use of incentive ratemaking as an alternative or a supplement to cost-of-service regulation. Thus, we have focused on analyzing utility incentives for supply- and demand-side resource acquisition and planning.

- For the Arizona Residential Utility Consumers Office (RUCO), Tellus advocated the termination of Arizona Public Service Company's fuel adjustment clause.

- Tellus advised LEAF (Legal Environmental Assistance Foundation) and the Pace University Center for Environmental Legal Studies regarding the implementation of revenue decoupling mechanisms for Florida's electric utilities.

Industry Structure

Utilities are restructuring themselves to meet increased competition. In this context, we have analyzed the impacts of utility mergers, acquisitions, and bankruptcies. For the Kansas Citizens Utility Ratepayers Board (CURB), Tellus assessed the economics of the merger of Kansas Power & Light and Kansas Gas & Electric and its impact on the utilities' ratepayers, and made rate recommendations.

For More Information

The Electricity Program at Tellus plays an active role in electric utility planning and regulation throughout the U.S. For more information, contact Mr. Bruce Biewald, Manager of the Electricity Program at Tellus Institute.

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Education

B.S. Massachusetts Institute of Technology, 1981.
Architecture, Building Technology, Energy Use in Buildings.

Harvard University Extension School 1989/90.
Graduate courses in micro and macroeconomics.

Experience

1989 - Senior Scientist, Energy Group/Tellus Institute. Manager of the Electricity Program.

Responsible for research and consulting on all aspects of electric power system planning and regulation including climate change policy, environmental externalities valuation, nuclear and fossil power plant costs and performance, power supply contracts and performance standards, nuclear plant decommissioning and radioactive waste issues, energy conservation and demand-side management, rates and fuel adjustment clause analysis, electric power system reliability, avoided costs, fuel prices, purchased power availability and cost, production costing modelling, economic analysis of power plants and resource plans, risk analysis, and integrated resource planning.

- Expert testimony in state regulatory proceedings in more than a dozen states and in twice this number of proceedings.
- Papers published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and various conference proceedings.
- Invited to speak by American Society of Mechanical Engineers (ASME), International Atomic Energy Agency (IAEA), National Association of Regulatory Utility Commissioners (NARUC), National Association of Utility Consumer Advocates (NASUCA), the Latin American Energy Association (OLADE), and the Swedish Environmental Protection Agency (SNV).

- Recent electricity program clients include:

  American Lung Association
  American Wind Energy Association
  Arkansas Public Service Commission
  Boston Edison Company Settlement Board
  British Columbia Energy Coalition
  Clean Water Action
  Colorado Energy Office
  Delaware Public Service Commission
  District of Columbia Public Service Commission
  Electric Power Research Institute (EPRI)
  Energy Foundation
  Environmental Law and Policy Center of the Midwest
  Georgia Consumers Utility Counsel
  Illinois Citizens' Utility Board
  Institute for Local Self-Reliance
  Izaak Walton League of America
  Kansas Corporation Commission
  Land and Water Fund of the Rockies
  Maryland Public Service Commission
  Massachusetts Division of Energy Resources
  Mid-Atlantic Energy Project
  Minnesota Center for Environmental Advocacy
  Minnesotans for an Energy Efficient Economy
  Missouri Office of Public Counsel
  National Association of Regulatory Utility Commissioners (NARUC)
  Nevada Office of Consumer Advocate
  New Hampshire Consumer Advocate
  New Jersey Office of Public Advocate
  Ohio Office of the Consumers' Counsel
  Pennsylvania Office of Consumer Advocate
  Renewable Northwest Project
  Scenic Hudson, Inc.
  Tennessee Valley Authority
  U.S. Department of Energy
  U.S. Environmental Protection Agency
  Vermont Department of Public Service
  West Virginia Consumer Advocate
  Wisconsin Citizens' Utility Board

1980-1988 Research Associate, later Associate Scientist, Tellus Institute (formerly Energy Systems Research Group (ESRG)).

Testimony

Agency	Case or Docket No.	Date	Topic
Colorado Public Utilities Commission	94A-516A (Tellus No. 95-001)	January 1995	Support for the Settlement agreement between WestPlains Energy and the LAW Fund regarding Application for a Certificate of Public Convenience and Necessity for a Combined Cycle Generating Facility filed by WestPlains on 9/27/94
Public Service Commission of Nevada	94-9002 (Tellus No. 94-193)	November 1994	Environmental impacts of a proposed power plant
Nuclear Decom-missioning Finance Committee of New Hampshire	93-001 (Tellus No. 94-156)	September 1994	Seabrook decommissioning cost, spent fuel storage and cost collection methodology (joint testimony with William Dougherty)
Public Service Commission of Wisconsin	6630-CE-197 and 6630-CE-209 (Tellus No. 93-164)	September 1994	Point Beach externalities, economics, spent fuel storage and aging (joint testimony with William Dougherty)
British Columbia Utilities Commission	(Tellus No. 94-195)	August 1994	Greenhouse gas emissions and environmental externalities policy
Public Service Commission of Wisconsin	05-EI-14 (Tellus No. 93-217)	February 1994	Cost of decommissioning Point Beach and Kewaunee nuclear power plants
		February 1994	(Rebuttal Testimony) (Surrebuttal Testimony)
Delaware Public Service Commission	PSC Docket 91-39 (Tellus No. 92-053A)	September 1992	Comments on testimony of Delmarva Power & Light Co. Witness Robert Koppe; support for an alternative set of plant performance targets; recommendation of a methodology to be used in determining performance targets in future cases
Massachusetts Department of Public Utilities	DPU No. 91-131 (Tellus No. 91-085C)	December 1991	Internalization of environmental externalities and the appropriate role of the Department of Public Utilities; greenhouse gas valuation and policy

Massachusetts Department of Public Utilities	DPU No. 91-131 (Tellus No. 91-085B)	October 1991	Environmental externalities valuation, emissions effects and global warming
Massachusetts Department of Public Utilities	89-141, 90-73, 90-141, 90-194, and 90-270	December 1990	The incorporation of environmental externalities in specific utility RFPs
Massachusetts Department of Public Utilities	90-55	June 1990	Costs and benefits of high-efficiency gas heating equipment
Massachusetts Department of Public Utilities	86-36-G and 89-239 (ESRG 90-015)	March 1990	Environmental externalities of electric resources
Florida Public Service Commission	890973-E1 (ESRG 89-194B)	January 1990	Integrated energy planning, power plant emissions, and nuclear plant performance
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-090C)	October 1989	Generating Capacity Requirements of the Philadelphia Electric Company and the Pennsylvania-New Jersey-Maryland Interconnection
Maryland Public Service Commission	8199 (ESRG 89-156)	October 1989	Performance Standards for Coal, Oil and Nuclear Power Plants
Michigan Public Service Commission	U-9172 (ESRG 88-100)	April 1989	Economic Analysis of the Palisades Power Purchase Agreement. Ratepayer impacts, incentives, and implications for plant operation and decommissioning
Pennsylvania Public Utility Commission	P-870216 P-880283 P-880284 P-880286 (ESRG 88-026)	March 1989	Allegheny Power System Generation Planning and Avoided Costs (Supplemental Testimony)
Michigan Public Service Commission	U-8880 (ESRG 87-91B)	Feb. 1988	Detroit Edison Company Power Supply Costs Power Supply Costs, economics of Fermi "buy-back" purchase, nuclear fuel expense, oil costs, and power transactions

Michigan Public Service Commission	U-8866 (ESRG 87-91A)	Dec. 1987	Consumers Power Company Power Supply Costs, including projections of oil prices and purchased power costs
Pennsylvania Public Utility Commission	R-850220 (ESRG 87-17)	Sept. 1987	Economic Analysis of the West Penn Power Company's participation in the Bath County Pumped Storage Project, and Allegheny Power system capacity reserve requirements
		Oct. 1987	(Sur-rebuttal Testimony)
Arizona Corporation Commission	U-1345-85-367 (ESRG 86-42L)	Feb. 1987	Palo Verde Decommissioning Cost
Michigan Public Service Commission	U-8545 (ESRG 85-55/B)	Dec. 1986	Consumers Power Company Power Supply Costs, projected costs of oil and purchased power, economic evaluation of the Big Rock Point nuclear unit
Public Service Commission of Indiana	38045 (ESRG 86-56)	Nov. 1986	Northern Indiana Public Service Company System Reliability and Excess Capacity
California Public Utility Commission	84-06-014 & 85-08-025 (ESRG 86-44)	July 1986	Diablo Canyon decommissioning cost and collection issues
Michigan Public Service Commission	U-8042R (ESRG 86-16)	June 1986	Review of Consumers Power Co. system operations during 1985 and economic evaluation of the Big Rock Point nuclear unit
Michigan Public Service Commission	U-8291 (ESRG 85-48/B1)	April 1986	Detroit Edison Co. power supply costs, application of a multi-area dispatch model

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Maine Public Service Commission	85-132 (ESRG 85-28)	Jan. 1986	Standard and Long-Term Rates for Cogeneration and Small Power Production
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Arkansas Public Service Commission	84-249-U (ESRG 85-08/2)	June 1985	Impact of the Grand Gulf nuclear unit upon Arkansas Power and Light Co. and Middle South Utilities electricity production costs
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October 1982	*Report on Electricity Conservation in the State of Vermont: Assessing the Potential and Developing Program Strategies.* A Report to the Department of Public Service. ESRG Study No. 82-23. Co-author.
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December 1994	"Environmental Externalities: Highways and Byways," *NRRI Quarterly Bulletin*, Vol. 15 No. 4. Bruce Biewald, Paul Chernick and Bill Steinhurst. Presented at NARUC's 5th National Conference on Integrated Resource Planning, Kallispell, Montana, May 15-18, 1994.
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September 1994	"Alternative Closed Cycle Cooling Systems for Power Plants: A Framework of Evaluation in Integrated Resource Planning," proceedings of the Ninth NARUC Biennial Regulatory Information Conference, Columbus, OH. Sept. 7-9. Singh and Biewald.
August 1994	"Misconceptions, Mistakes and Misnomers in DSM Cost-Effectiveness Analysis, Or What Do You Really Mean By T.R.C.?" ACEEE 1994 Summer Study, Pacific Grove, CA. August 28-Sept. 2. Fulmer and Biewald.
May 1994	"Modelling Renewable Electric Resources: A Case Study of Wind Power." Presented at: WINDPOWER 1994, Sponsored by American Wind Energy Association, Minneapolis, Minnesota. May 9-13. Bernow, Biewald, Singh.

May 1994	"National Climate Change Policy and Clean Air Act Compliance: A Case Study of Combined CO_2/SO_2 Reduction," proceedings of NARUC's 5th National Conference on Integrated Resource Planning, Kalispell, Montana. May 15-18. Bernow, Biewald, Fulmer, Woolf, Wulfsberg and Solomon.
October 1993	Modelling Renewable Electric Resources: A Case Study of Wind Reliability," presented at: NARUC-DOE National Regulatory Conference on Renewable Energy, Savannah, GA. Oct 3-6. Bernow, Biewald, Singh.
April 1993	"Environmental Sustainability as a Goal in Resource Planning and Policy," Office of Technology Assessment, Washington, DC. Bernow and Biewald.
September 1992	"Climate Change and the U.S. Electric Sector," presented at NARUC's 4th National Conference on Integrated Resource Planning, Burlington, VT. Biewald and Bernow.
September 1992	"Coordinating Clean Air Act Compliance with Integrated Resource Planning: The Role of Externalities", invited paper at Eighth NARUC Biennial Regulatory Information Conference, Ohio State University, Columbus, Ohio. September 9-11. Bernow, Biewald, Wulfsberg.
September 1992	"Direct Environmental Impacts of Demand-Side Management," American Council for an Energy Efficient Economy (ACEEE) 1992 Summer Study. Bernow, Ackerman, Biewald, Fulmer, Shapiro and Wulfsberg.
May 1992	"Modelling Fuel Cycle and Site-Dependent Environmental Impacts in Electric Resource Planning", invited paper at OECD-IEA Expert Workshop on Life-Cycle Analysis of Energy Systems. Paris, France. May 18 and 19, 1992. Bernow and Biewald. *Proceedings* published OECD/IEA Paris, 1993.
September 1991	"Computer Model Use in Energy Conservation Planning," presented at the Latin American Energy Organization (OLADE) Seminar on Power Systems Computer Modelling in Quito, Ecuador, September 23-25, 1991.
September 1991	"Environmental Externalities Measurement: Quantification, Valuation and Monetization," Bernow, Biewald and Marron, in *External Environmental Costs of Electric Power*, proceedings of a German-American workshop, Ladenburg, FRG, October 23-25. Edited by Olav Hohmeyer and Richard Ottinger. Published by Springer-Verlag (Berlin, Heidelberg, New York).
May 1991	"Some Microcomputer Tools for Least Cost Integrated Energy Planning: ECO, LEAP and EDB," presented at workshop on Energy Pricing and Planning, Bratislava, Czechoslovakia, May 21-22, 1991. Biewald and Salgo.
March 1991	"Confronting Uncertainty: Contingency Planning for Decommissioning" *Nuclear Decommissioning Economics*, Chapter 18 of a special issue of *The Energy Journal*, Volume 12. The International Association for Energy Economics. Biewald and Bernow.

March 1991	"Avoided Emissions and Environmental Dispatch," presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991. Biewald and Bernow.
March 1991	"Environmental Benefits of DSM in New York: Long Island Case Study," presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991. Biewald and Bernow.
March 1991	"Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," *Electricity Journal*. Bernow, Biewald and Marron.
October 1990	"EDB: A Flexible Database System for Energy-Environmental Analysis," presented at International Atomic Energy Agency (IAEA) Technical Committee Meeting on "Development of a Database for Comparative Health and Environmental Impacts of Various Energy Systems," October 15-19, 1990 in Vienna, Austria. Biewald, Lazarus, and Von Hippel.
October 1990	Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation," presented at NARUC Conference on Externalities, Jackson Hole, Wyoming. Bernow, Biewald and Marron.
September 1990	"An Assessment of Demand-Side Management Models and Their Use and Applicability in Canadian Utilities," Proceedings of the Canadian Electrical Association Demand-Side Management Conference, Halifax, Nova Scotia. Adelaar and Biewald.
September 1990	"Avoided Cost Contracts Can Undermine Least Cost Planning," *Energy Policy*. Bernow, Biewald and Marron.
September 1990	"Environmental Externalities Measurement: Quantification, Valuation, and Monetization," Proceedings of the Seventh NARUC Biennial Regulatory Information Conference. Bernow, Biewald and Marron.
June 7, 1990	"Do We Really Need Nuclear Generating Companies?", *Public Utilities Fortnightly*.
November 1989	"The Indexing of Energy Rates Paid to Non-Utility Resources: Some Threats to Least-Cost Electricity Planning." Bernow, Biewald, Marron.
March 1989	"Nuclear Power Economics: Construction, Operation and Disposal". Biewald and Marron.
September 1988	"Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity", Proceedings of the Sixth NARUC Biennial Regulatory Information Conference. Bernow and Biewald.
October 29, 1987	"Nuclear Power Plant Decommissioning: Cost Estimation for Power Planning and Ratemaking," *Public Utilities Fortnightly*. Bernow and Biewald.

August 1987	"Cost and Performance of Boiling Water Reactors," *Public Utilities Fortnightly*. Bernow, Biewald and Woolf.

Other Professional Activities

June 1992	Invited Speaker on environmental externalities, ASME "ECO World" conference in Washington, D.C.
February 1992	Invited Speaker, Association of Energy Engineers, Boston, Massachusetts.
November 1991	Presentation of Acid Rain Abatement Optimization Model to the Swedish Environmental Protection Agency, Solna, Sweden.
May 1990	Training on Methods for Calculating Electric System Avoided Costs, provided to energy planners and policy makers from five Southeast Asian countries sponsored by U.S. Agency for International Development and administered by the Institute of International Education.
June 1988	Invited Speaker, National Association of State Utility Consumer Advocates (NASUCA) Mid-Year Meeting, Annapolis, Maryland.
April 1988	Invited Speaker, Conference on New Developments in Nuclear Decommissioning Costs and Funding Methods, sponsored by the Northeast Center for Professional Education, Washington, D.C.

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$$\text{Net Lost Revenues}_Y = \sum_{r=1}^{r=n}[(\text{Fixed Cost}_{kWh,r} \times \text{DSM Savings}_{kWh,r}) + (\text{Fixed Cost}_{kW,r} \times \text{DSM Savings}_{kW,r})]$$

- Net lost revenues are the sum over rate classes r = 1 to n to calculate net lost revenues for the single program year Y.

$$\text{Fixed Cost}_{kWh,r} = \text{Retail Energy Rate}_{kWh,r} - \text{Short-Run Variable Cost}_{kWh,r}$$

$$\text{Fixed Cost}_{kW,r} = \text{Retail Demand Charge}_{kW,r} - \text{Short-Run Variable Cost}_{kW,r}$$

- $\text{Fixed Cost}_{kWh,r}$ and $\text{Fixed Cost}_{kW,r}$ represent fixed costs recovered through retail energy rates and retail demand charges, respectively.

$$\text{DSM Savings}_{kWh,r} = \sum_{m=1}^{m=n}(\text{Unit Energy Savings}_{m,r} \times \text{Participants}_{m,r})$$

$$\text{DSM Savings}_{kW,r} = \sum_{m=1}^{m=n}(\text{Unit Demand Savings}_{m,r} \times \text{Participants}_{m,r})$$

- To calculate savings in each rate class, the last two expressions are summed over measures m = 1 to n.

Source: "Assessment of Net Lost Revenue Adjustment Mechanisms for Utility DSM Programs", Lester W. Baxter, Oak Ridge National Laboratory. ORNL/CON-408. January 1995.

CASE 93-M-0229: Guideline on Flexible Rates

The foregoing discussion leads to the adoption of the following general guidelines for flexible rates:

1. The intent of flexible rates for electric customers is to maintain contestable customers on the utilities' systems, in a way that benefits all ratepayers.

2. Flexible rates should be available for electric customers who have realistic competitive alternatives. A utility is not mandated to offer such rates if, in the utility's judgement, the rates would not be advantageous to the utility's customers as a whole.

3. The tariffs in place for Niagara Mohawk, NYSE&G, and RG&E should serve as models for flexible rates. Appendix B summarizes the main provisions of each of these tariffs.

4. The loss of revenues due to discounts should be shared between shareholders and ratepayers. The extent and manner of sharing will be determined in the context of individual rate cases.

5. Independent and comprehensive DSM audits are required in conjunction with the offering of flexible rates, but there will be a flexible approach to implementation.

6. The potential cost to the customer of complying with environmental regulations sufficient to meet minimum environmental permitting requirements will be taken into consideration when determining whether a customer has a realistic competitive alternative.

7. A floor price for flexible rates will be calculated by each utility, and will generally be set at no lower than the marginal cost of service to the customer plus 1¢/kWh.

8. Prices in contracts for flexible rates generally will not be fixed for longer than a seven-year period, unless a longer term is approved by the Commission in response to utility's petition.

9. Utilities offering flexible rate must file quarterly reports on the use of these rates, including information about the number of contracts, amount of load, percentage of discounts, effect of DSM audits, and environmental considerations as they relate to the feasibility of competitive alternatives with regard to the acquisition of needed environmental permits (referred to in guideline 6 above). Staff will analyze these reports and provide regular updates to the Commission.

SUMMARY OF EXISTING FLEXIBLE RATES

NEW YORK STATE ELECTRIC & GAS CORPORATION'S
SERVICE CLASSIFICATION NO. 13

A. Eligibility

To receive service under this service classification, a customer must, among other things:

1. Submit a strategic operating plan that includes an appropriate showing to the company of the favorable economics, viability of alternative services of electricity, along with an assessment of competitive factors including cost factors within the customer's market;

2. Have electricity costs constituting at least 7.5% of the final product costs, or an annual high billing demand of 5,000 kW or greater; and

3. Provide the results of a comprehensive production analysis and energy audit, along with a requirement to install all measures identified by the audit that have a reasonable payback period.

B. Terms of Service

Fixed prices can be set for at least 12 months, but no more than 36 months, unless the company thinks a longer term (of up to seven years) would produce additional benefits to non-participating customers.

C. Pricing

Specific pricing for any individually negotiated contract will, at a minimum, recover all incremental costs the company incurs in serving the customer, plus a reasonable contribution toward system costs.

D. Sharing

For contracts where customers are eligible because they have 7.5% electricity costs, 70% of the difference between the revenues that a customer was forecasted to generate and the actual revenues that the customer does generate will be recovered from or flowed through to customers, and 30% will be recovered from shareholders.

NIAGARA MOHAWK POWER CORPORATION'S
SERVICE CLASSIFICATION NO. 10

A. Eligibility

To receive service under this service classification, a customer must, among other things:

1. Provide information demonstrating to the company's satisfaction that on-site generation is a viable competitive alternative to the continued purchase of electric power at the company's otherwise applicable rates;

2. Have a demand of 2000 kW in any two consecutive months; and

3. Agree to provide the company with a recent energy audit. The audit can be performed at no expense to the customer. The purpose of the audit is to identify potential energy efficiency improvements; it will provide reliable cost and benefit information on all electric energy efficiency improvements with reasonable paybacks.

B. Terms of Service

Fixed prices can be set for at least 12 months, but no more than 36 months.

C. Pricing

Specific pricing for any individually negotiated contract will, at a minimum, recover all incremental costs the company incurs in serving the customer, plus a contribution to fixed costs.

D. Sharing

80% of the difference between the revenues that a customer was forecasted to generate and the actual revenues that the customer does generate will be recovered from or flowed through to customers, and 20% will be recovered from shareholders.

ROCHESTER GAS & ELECTRIC CORPORATION'S SERVICE CLASSIFICATION NO. 10

A. Eligibility

To receive service under this service classification, a customer must, among other things:

1. Provide, subject to a confidentiality agreement, reasonable documentation demonstrating to the company's satisfaction evidence of a viable competitive alternative to the company's present service;

2. Have a demand of not less than 300 kW during any three of the previous 12 months; and

3. Agree to provide the company with a recent energy audit. The audit can be performed at no expense to the customer. The purpose of the audit is to identify potential energy efficiency improvements; it will provide reliable cost and benefit information on all electric energy efficiency improvements with reasonable paybacks.

B. Terms of Service

Fixed prices can be for at least 12 months, but no more than 36 months, unless the company thinks a longer term (of up to seven years) would produce additional benefits to non-participating customers.

C. Pricing

Specific pricing for any individually negotiated contract will must reflect the company's assessment of the pricing and terms required to respond to the customer's competitive options and must be determined to maximize the contribution to total company margins provided by service under the contract. Charges can be no lower than the company's incremental costs.

D. Sharing

70% of the difference between the revenues that a customer was forecasted to generate and the actual revenues that the customer does generate will be recovered from or flowed through to customers, and 3O% will be recovered from shareholders.

Convention Floor Resolution No. 10

Resolution on Competition, the Public Interest, and Potentially Stranded Benefits

WHEREAS, State and federal electric utility regulators are exploring the restructuring of the electric utility industry so as to provide lower energy service costs and greater consumer choice through the enhanced use of competition and market mechanisms; and

WHEREAS, The laws and traditions of electric utility regulation have long recognized the electric industry as a critical element of national infrastructure greatly affected with the public interest; and

WHEREAS, The franchise system of regulation has encouraged electric utilities, pursuant to state laws, to secure important public benefits in the provision of utility services, including:

- system reliability and fuel diversity;
- responsible management of the environmental impacts of electric generation;
- the promotion of systematic investments in energy efficiency, thus improving the nation's energy security and lowering energy costs to the nation's economy;
- innovative rate designs that have served national and state objectives in such areas as rate stability, equity, economic development, and meeting the specific needs of low-income customers;
- a system of support for research and development for the electric industry; and
- investments in commercialization strategies to speed growth in markets for renewable energy technologies; and

WHEREAS, Utility-sponsored energy efficiency programs have become a significant element of the nation's energy policy (according to the Energy Information Administration, by 1993, cost-effective utility DSM programs provided over 20,000 megawatts of peak load reduction and saved more than 40 million megawatt-hours annually, and such programs were growing at more than 20 percent annually) and utility-sponsored programs were expected to provide a majority of the national goals for energy efficiency savings set out in the 1992 National Energy Strategy; and

WHEREAS, These widespread public benefits could be undermined or lost unless integrated into new proposals which are being developed for a more competitive marketplace; and

WHEREAS, It is the responsibility of state and federal electric utility regulators to assure that these vital public benefits are not "stranded", but are well-served in new electric industry structures and in the transition to them; and

WHEREAS, Public utility commissions will generally have the authority and the responsibility to protect these vital interests through (a) new regulatory regimes for assuring that increased competition is both fair and free of major market imperfections and

(b) continued regulation of those sectors of the industry that may remain natural monopolies, such as distribution and transmission activities; now, therefore, be it

RESOLVED, By the National Association of Regulatory Utility Commissioners (NARUC) at its 106th Annual Convention in Reno, Nevada, that a fundamental responsibility of state and federal electric utility regulators in this transition period is to assure that vital public interests and established public benefits will be preserved in any restructuring of the electric utility industry; and be it further

RESOLVED, That NARUC shall communicate to the Federal Energy Regulatory Commission, Congress, Department of Energy, and other responsible federal agencies the conviction that any federal actions taken with respect to electric industry competition and restructuring must not foreclose the ability of the states and state regulatory commissions to secure these public benefits within the several states; and be it further

RESOLVED, That, in their individual deliberations over the restructuring of the electric industry, state and federal regulators are encouraged to establish the criteria by which alternative proposals are to be judged, and that these criteria should include: reliability and fuel diversity, environmental protection, energy efficiency, equity, economic development, the needs of low-income customers, and research and development; and be it further

RESOLVED, That the members of NARUC are committed to promote these criteria in cooperation with federal regulators and state legislatures to further the long-term public interests of both the nation and individual states.

Sponsored by the Committee on Energy Conservation
Adopted November 16, 1994

DOD Statement No. 1

4/27/95
Hbg
Jar

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, et al.	)	
v.	)	DOCKET NO. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	)	

DIRECT TESTIMONY AND EXHIBITS

OF THOMAS J. PRISCO

For

THE DEPARTMENT OF DEFENSE AND
THE FEDERAL EXECUTIVE AGENCIES

Date Due: 7 April 1995

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

A. My name is Thomas J. Prisco. My office address is U.S. Army Litigation Center, JALS-RL, Suite 400, 901 North Stuart Street, Arlington, VA 22203-1837.

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

A. I am employed by the Regulatory Law Office, United States Army Office of The Judge Advocate General, Department of the Army, as a Staff Accountant and Financial Advisor.

Q. PLEASE SUMMARIZE YOUR PAST WORK EXPERIENCE.

A. Prior to assuming my present position in October, 1987, I had been employed by the United States Army Information Systems Command as a Systems Accountant, responsible for developing and implementing a cost chargeback system for information services. From 1978 to 1983, I held various positions with the U.S. Army Computer Systems Command, including Staff Accountant, Contract Officer Representative, and Chief, Accounting Operations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree with a major in Accounting from the University of Scranton in December, 1977. Additionally, I have taken numerous professional courses which include Price and Cost Analysis, U.S. Army Financial Management, and Computer Performance and Capacity Management. I completed the NARUC Annual Regulatory Studies Program. I am a member of American Society of Military Comptrollers.

Q. WHAT ARE THE RESPONSIBILITIES AND DUTIES ASSOCIATED WITH YOUR PRESENT POSITION?

A. As Staff Accountant and Financial Advisor with the Regulatory Law Office, I analyze testimony, exhibits, and supporting data submitted by utilities to regulatory bodies in justification of proposed rate increases/decreases; advise office attorneys in accounting matters; draft proposed cross-examination of company witnesses; prepare statements and exhibits for use in regulatory proceedings; and present testimony before utility commissions to protect the consumer interests of the Federal Government.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. I have participated in regulatory proceeding as outlined on attached Exhibit TJP-1.

Q. WOULD YOU OUTLINE THE SUBJECT MATTER OF THE EXPERT TESTIMONY YOU HAVE PRESENTED BEFORE REGULATORY

COMMISSIONS?

A. My testimony has addressed the overall revenue requirements, depreciation, capital structure, cost of capital, integrated resource planning, rate design, incentive rates, rate base and appropriate tariffs of communications, electric, gas, and water utilities.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the consumer interest of Department of Defense and All Other Federal Executive Agencies (hereinafter called "DOD").

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

A. I have reviewed the rate filing of Pennsylvania Power and Light Company (PP&L) and have addressed a number of revenue requirements issues which result in a decrease to the proposed $261,635,000 by $183,436,000. See DOD Adjustments to Operating Income, Exhibit TJP-4.

Q. PLEASE DESCRIBE IN GENERAL TERMS HOW THE FEDERAL GOVERNMENT BUYS ELECTRIC UTILITY SERVICE IN PENNSYLVANIA, PRESENTLY?

A. At the current time most of the electricity procured by federal facilities in Pennsylvania is purchased under contracts which make reference to, or incorporate utility rates regulated by the Commission. Exhibit TJP-2, is a two page exhibit consisting of the delegation of authority from the GSA, to the Secretary of Defense, dated February 15, 1995, to provide representation of the consumer interest of federal civilian agencies in this proceeding.

Q. WHAT RATE SCHEDULES ARE USED BY FEDERAL INSTALLATIONS TO PROCURE POWER FROM PP&L?

A. Most billings to federal agencies for electric service were on Rate LP-5 for service to military and naval installations. Federal civilian agencies procure electricity from PP&L on several rate schedules. Small federal facilities such as postal buildings and civilian agencies purchase electricity on commercial rates administered by the GSA. Post offices procured about $1,100,000 in electric service in the 12 months ending September 30, 1994. Federal prisons purchased about $660,000 in electric service. The Veteran's Hospital facilities procured about $490,000 of electric service. Other civilian federal agency purchases of electric service were about $670,000 for the 12 months ending September 30, 1994.

Q. TELL US MORE ABOUT THE POWER BILLINGS INCURRED BY MILITARY AND NAVAL FACILITIES.

A. Total billings to the Army by PP&L were about $7.8 million for service during the 12 months ending September 30, 1994. Billings to the Navy at Mechanicsburg were about $3.5 million. Again, the bulk of these power purchases were on rate LP-5. Attached is my Exhibit TJP-3 summarizing LP-5 usage by selected military installations.

Q. ARE YOU RECOMMENDING ANY CHANGES IN PP&L'S PROPOSED CLASS COST OF SERVICE STUDY?

A. No.

Q. ARE YOU MAKING ANY RECOMMENDATIONS REGARDING PP&L'S PROPOSED RATED DESIGN IN THIS PROCEEDING?

A. No.

Q. WHICH TOPICS WILL YOUR DIRECT TESTIMONY ADDRESS IN THIS PROCEEDING?

A. The testimony which I am filing will addresses the following topics:

a. Rate Case Expenses
b. Interest on Customer Deposits
c. Voluntary Early Retirement Program (VERP)
d. Decommissioning Expenses for Fossil Fuel Facilities
e. Adjustments to the Annual Accrual for

Decommissioning Nuclear Facilities

f. Adjustment to Shorten Fossil Fuel Plant

g. Levelizing Amortization of Nuclear Power Plants

As can be concluded from the list above, I have not addressed a number of components from the PP&L filing. However, this does not constitute and endorsement of PP&L's position.

Q. PP&L HAS NORMALIZED THEIR RATE CASE EXPENSES IN THIS PROCEEDING DO YOU AGREE?

A. No. PP&L has not filed a rate base case since 1985, and it would not be unreasonable for the Commission to spread recovery of rate case expenses over a period of time. A number of jurisdictions in which I have appeared (Maryland, New Jersey, Texas, etc.) use a three year average to determine the proper level of rate case expenses. I recommend that PP&L recover expenses for rate cases based on a three average. Use of a three year average in this proceeding will result in an additional decrease in rate case expenses of $249,000. See Exhibit TJP-5.

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

A. PP&L is paying an excessive interest rate on customer deposits. The Company in this proceeding is using an 11 percent interest rate on customer deposits. This is the same rate authorized by the Commission in 1981. Interest rates have declined substantially since that period, and PP&L's filing should have requested an appropriate adjustment. I do not object to customers receiving a return on their deposits. However, the interest rate should be commensurate with current market rates. I believe a fitting rate for customers deposits could be tied to the current interest rate paid on United States Savings Bonds. This would fairly compensate customers who loose the use of their deposit. At the same time it will be fair to all customers who pay the interest. I have used the 7.5% rate which is the approximate of U.S. Savings (EE) Bonds. The use of a 7.5% would result in a decrease in interest expense of $39,000. See Exhibit TJP-6.

Q. HAVE YOU REVIEWED PP&L'S ADJUSTMENT FOR VOLUNTARY EARLY RETIREMENT PROGRAM (VERP)?

A. Yes

Q. DO YOU AGREE WITH PP&L CALCULATION OF THE ADJUSTMENT FOR VERP WHICH RESULTS IN A DECREASE OF $13,917,000?

A. No. According to Mr. Berish's testimony on page 13, lines 12 and 13, 580 employees in addition to those employee reductions which were already anticipated for the Company's 1995 budget volunteered for the program. Taking this information into consideration and using Company witness Bernini's average monthly wage per employee of $4,523 from PP&L's wage adjustment in Exhibit Future 1, Schedule D-5, I calculated the different wage savings. I used the same logic to calculate the VERP savings that Mr. Bernini utilized to arrive at his September 1995 wage expense. As shown on Exhibit TJP-7, this will result in a annual payroll savings above Mr. Berish's estimate of $3.2 million.

Q. IS THE USE OF AN AVERAGE WAGE UNFAIR TO THE COMPANY?

A. I do not believe so. I anticipate that a substantial number of employees who are waiting to take advantage of the early retirement program are at the upper end of the pay scale. Removing these higher paid employees from the payroll will reduce the average pay.

Q. PP&L IS REQUESTING THAT A FUND BE ESTABLISHED TO DECOMMISSION FOSSIL FUEL FACILITIES HAVE YOU LOOKED AT THIS ISSUE?

A. Yes. This Commission should reject PP&L proposal for decommissioning of their fossil fuel facilities. The Company is requesting $52,818,000 in decommissing cost related to fossil fuel facilities. See Exhibit TJP-8. At this time there is no reason to believe that existing plants will not receive life extending upgrades. Also there is no reason to believe that PP&L (or some third party) may not build a future plant on the same site, given the (environmental) difficulty sometimes incurred in siting all power plants. The TLG decommissioning study also incorporates the shortened lives of the fossil fuel facilities for which the Company has yet to make a determination if they will close. Should the Commission decide not to shorten the lives of the steam plants the study by TLG will be flawed.

Q. HAVE YOU REVIEWED THE COMPANY'S REQUEST FOR DECOMMISSIONING EXPENSE FOR THEIR NUCLEAR POWER FACILITIES?

A. Yes. There is no reason to believe that the costs required for decommissioning by the Nuclear Regulatory Commission are faulty. At the present time there is no way to know what technological advances the industry will make over the next 25 years. Condsidering that the Susquehanna units are not to be deactivated until the 2020's the probability is that costs will decrease as more experience is gained by the industy about nuclear plant decommissioning. There is also the possibility that life extension methods will be developed to lengthen the life of the nuclear facilities. At this time I would recommend that the Commission not change its present practice for recouping decommissioning costs. See Exhibit TJP-9.

Q. MR. PRISCO, PP&L IS PROPOSING IN THIS FILING A CHANGE IN THE DEPRECIABLE LIFE OF SOME OF THEIR FOSSIL FUEL FACILITIES. HAVE YOU LOOKED AT THE COMPANY'S REQUEST?

A. Yes.

Q. BASED ON THE INFORMATION PRESENTED BY PP&L DO YOU AGREE THAT THIS CHANGE IS APPROPRIATE?

A. No. PP&L's proposal to revise the deactivation dates for several of their steam production plants should be rejected by the Commission. The new deactivation date decreases the life for Martins Creek 1 & 2 by 12 years. Currently the deactivation date for these units is June 30, 2015, and PP&L has proposed a deactivation date of June 30, 2003. The deactivation date for Holtwood is changed from June 30, 2009 to June 30, 2003, a six year decrease. Sunbury's deactivation date has changed from

June 30, 2010 to June 30, 2003 a seven year decrease. Writing off these plants by 2003 will increase revenue requirements in this case ostensibly out of concern for unidentified changes in environmental regulations. PP&L's response (paragraph 2) to interrogatory QTS-RB-23D, submitted by the Office of Trial Staff dated January 13, states:

> Referring to the analyses for Sunbury (Section 5), Martins Creek (Section 6), and Holtwood (Section 7), the dominant feature of each is that, <u>while continued operation is favored over retirement</u> (emphasis added), the margin by which continued operation is favored is relatively small. This implies greater exposure to shutdown for units at these stations than for units at Montour (Section 3) or Brunner Island (Section 4) as a result of uncertainties in the estimates used in the analyses and <u>events which cannot currently be foreseen</u> (emphasis added). In particular, the Company is concerned that the need for significant reductions of NOx emissions under Title I of the 1990 Clean Air Act Amendments and reductions of emissions of air toxics under Title III of the 1990 Amendments are two cost exposures, not included in the May, 1994 analyses, which <u>could erode</u> (emphasis added) the economic benefit of continued operation through 2013.

PP&L state in paragraph three of the same interrogatory states:

> Attachment 2 provides copies of Section 184 of Title I of the 1990 Clean Air Act Amendments and the Memorandum of Understanding among the states of the Ozone Transport Region which form the basis for PP&L's concern regarding NOx controls. Attachment 3 is a copy of Section 112(n)(1) of Title III of the Amendments which is the basis of PP&l's concern regarding air toxics. The Company's current estimate of the exposure for NOx is that Selective Catalytic Reduction (SCR) systems <u>could required</u> (emphasis added). This technology is not commercially proven on the types of coal PP&L units burn, but an estimate of the cost exposure (in 1994 dollars) for units like Martins Creek 1 and 2 is

> $24 million in capital with annual operating costs of $6 million. Although it is not clear what pollutants, <u>if any</u> (emphasis added), are to be controlled and what control strategy might be required until air toxics studies are complete, the Company estimates that the exposure <u>might be</u> (emphasis added) the need to install high-efficiency bag filters with a cost exposure for units like Martins Creek 1 and 2 of $60 million in capital (2003 vintage dollars).

The Commission could see from the areas emphasized that there is considerable uncertainty as to what the future cost will be for these plants. These cost are not "known and measurable" and the commission should reject PP&L's request for decommissioning of fossil fuel plants. While some requlations of NOx may be issued in the near future, it is uncertain what if any cost impact compliance would have on PP&L operations. PP&L customers should not be required to annually fund $28 million based on speculative costs.

See Exhibit TJP-10.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS CONCERNING SHORTENING THE LIVES OF THE ABOVE MENTIONED PLANTS?

A. Yes. As recently as May 1994, PP&L projected retirement of these plants no sooner than 2009. No PP&L document dated before this filing shows that anyone in top management was aware of the projected "deactivation". of these coal plants (total capacity 735 MW). The Company in this filing has reduced the lives based on studies, but has not officially stated that the plants will be deactivated. PP&L has not stated how they plan to replace the 735 MW.

Q. PP&L IS RECOMMENDING IN THIS PROCEEDING TO LEVELIZE THE SUSQUEHANNA SINKING FUND DEPRECIATION. WHAT IS YOUR OPINION ON THIS ISSUE?

A. PP&L in Attachment A, Exhibit Future 1, identifies $33 million for levelizing the Susquehanna sinking fund. The Company has not justified the need to change from the current sinking fund method of depreciation for Susquehanna. Recommend the Commission reject PP&L's request for levelizing the sinking fund. See Exhibit TJP-11.

Q. MR. PRISCO, DID YOU MAKE ANY RECOMMENDATION REGARDING PP&L'S PROPOSED CAPITAL STRUCTURE OR COST OF CAPITAL?

A. I have made no changes in my exhibits regarding the proposed capital structure, and I have used the figures for preferred stock and debt proposed by PP&l. I did use a different cost of equity than proposed by PP&L, capital market conditions changed since the last base rate case nearly a decade ago. For purposes of calculating a revenue requirement on Exhibit TJP-4, I used the cost of equity capital found reasonable by the Pennsylvania Public Utility Commission in a recent electric utility case, decided on the day before this proceeding was filed by PP&L. In the Order entered December 29, 1994, in Pennsylvania Public Utility Commission ET Al. vs. West Penn Power Company PA PUC Docket No. R-00942986. The Commission awarded that electric utility a return on equity of 11.5 percent. For purposes of calculation of revenues, this return on equity affords PP&L a return similar to that currently available to an enterprise of similar risk in this part of the nation.

Q. HAVE YOU CONDUCTED ANY INDEPENDENT STUDIES TO SUPPORT THAT RECOMMENDED RETURN ON EQUITY?

A. No. Time and resource constraints made it impractical for me to address other issues and to conduct such independent studies. I also did not conduct an independent study regarding PP&L's proposed capital structure. It is possible that such independent studies of the cost of capital and capital structure would have resulted in a lower overall recommended return. See Exhibit TJP-12.

Q. MR. PRISCO, DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE PP&L PROPOSAL THAT THE ECR BE MODIFIED TO PERMIT RECOVERY OF THE PENNSYLVANIA JURISDICTIONAL PORTION OF NON-ENERGY REVENUE REQUIREMENTS ASSOCIATED WITH OFF

SYSTEM BULK POWER AND CAPACITY SALES?

A. This PP&L proposal was initially discussed in the direct testimony of PP&L witness Joseph M. Kleha, Exhibit I, Statement. If the Commission wants to give PP&L the incentive to increase system efficiency by better use of available capacity, the Commission should modify the ECR by returning to a method of treating non-energy revenues and revenue requirements in the manner employed prior to the decision in PA PUC Docket Nos. M-00910273, M-00910273, M-00920312 and M-00930406 effective April 7, 1994. PP&L's proposal shifts the risk to ratepayers that off system non-energy related sales revenues at current prices will be made in the future.

If the Commission wants to increase PP&L's incentive to procure fuel and/or purchased power effectively, consideration should be given to eliminating the ECR and collecting all ECR revenue requirements in base rates. The ECR mechanism was adopted by utilities and regulators to address volatility in utility fuel costs many years ago. In recent years, and in the future, if forecasters of fuel prices are to be believed, fuel prices may be much less volatile. Collecting all utility costs of service, including projected fuel costs, in the base rate proceeding would give PP&L added incentive to control fuel costs incurred.

Therefore, I recommend that PP&L proposal be rejected. I recommend that all non-energy revenues and revenue requirements related to off-system sales be given treatment in base rates in accord with the method used prior to the order approving the "Joint Petition For Settlement of Consolidated Proceedings" in PA PUC Docket Nos. M-00910273, M-00910273, M-00920312 and M-00930406 effective April 7, 1994.
Further, I recommend eliminating the ECR and that all of PP&L's costs of service, including energy related fuel costs, be included in the rates proposed in PP&L's next rate proceeding.

Q. HOW WOULD YOUR RECOMMENDATION AFFECT PP&L'S PROPOSED REVENUE REQUIREMENTS IN THIS CASE?
A. Overall there would be no change for both the ECR and base rates are under consideration. However, the amount collected in the ECR and the amount collected in base rates would be adjusted by the proposed non-energy related off-system revenues and revenue requirements.

Q. MR. PRISCO, HAVE YOU MADE ANY STUDIES AS TO WHETHER ALL THE GENERATING CAPACITY OF PP&L IS USED AND USEFUL IN PROVIDING JURISDICTIONAL SERVICE?
A. No. I have made no such study. I have made no

recommendation as to accounting adjustment to rate base or revenue requirements regarding any disallowance of excess capacity.

Q. MR. PRISCO, DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, *et al*.	)	
v.	)	DOCKET NO. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	)	

EXHIBITS

OF THOMAS J. PRISCO

For

THE DEPARTMENT OF DEFENSE AND
THE FEDERAL EXECUTIVE AGENCIES

Date Due: 7 April 1995

TESTIMONY OF THOMAS J. PRISCO
BEFORE REGULATORY AGENCIES
1989 TO PRESENT

COMPANY	PROCEEDING	JURISDICTION	ACTION & SUBJECT
LOUISVILLE GAS & ELECTRIC COMPANY	CASE NO. 10064	KENTUCKY	TESTIMONY REV REQMT
SOUTHWESTERN BELL TELEPHONE COMPANY	CASE NO. TC-89-14	MISSOURI	TESTIMONY REV REQMT
MOUNTAIN STATES TELEPHONE AND TELEGRAPH COMPANY	DOCKET NO. E-1051-88-146	ARIZONA	TESTIMONY REV REQMT
BALTIMORE GAS AND ELECTRIC COMPANY	CASE NO. 8910	MARYLAND	TESTIMONY REV REQMT
BALTIMORE GAS AND ELECTRIC COMPANY	CASE NO. 8251	MARYLAND	TESTIMONY REV REQMT
JERSEY CENTRAL POWER AND LIGHT COMPANY	BRC DOCKET NO. ER89110912J	NEW JERSEY	TESTIMONY REV REQMT
NEW JERSEY-AMERICAN WATER COMPANY	BRC DOCKET NO. WR91081399J	NEW JERSEY	SETTLEMENT NEGOTIATION
NEW JERSEY-AMERICAN WATER COMPANY	BRC DOCKET NO. WR92090908J	NEW JERSEY	TESTIMONY REV REQMT
TUCSON ELECTRIC POWER COMPANY	DOCKET NO. U1993-90-270	ARIZONA	SETTLEMENT NEGOTIATION
BALTIMORE GAS AND ELECTRIC COMPANY	CASE NO. 8478	MARYLAND	TESTIMONY REV REQMT

TESTIMONY OF THOMAS J. PRISCO
BEFORE REGULATORY AGENCIES
1989 TO PRESENT

COMPANY	PROCEEDING	JURISDICTION	ACTION & SUBJECT
POTOMAC ELECTRIC POWER COMPANY	CASE NO. 912	DISTRICT OF COLUMBIA	TESTIMONY REV REQMT
POTOMAC ELECTRIC POWER COMPANY	CASE NO. 929	DISTRICT OF COLUMBIA	TESTIMONY REV REQMT
POTOMAC ELECTIC POWER COMPANY	CASE NO. 8251	MARYLAND	SETTLEMENT NEGOTIATION
POTOMAC ELECTRIC POWER COMPANY	CASE NO. 8466	MARYLAND	SETTLEMENT NEGOTIATION
POTOMAC ELECTRIC POWER COMPANY	CASE NO. 8565	MARYLAND	SETTLEMENT NEGOTIATION
INTEGRATED RESOURCE PLANNING RULE MAKING FOR GAS UTILITIES	DOCKET NO. 91-677-G	SOUTH CAROLINA	TESTIMONY DSM
DEMAND SIDE OPTIONS & CONSERVATION PROCEEDING	DOCKET NO. 900834-EI	FLORIDA	ASSISTED COUNSEL
ATLANTA GAS LIGHT COMPANY	DOCKET NO. 4451-U	GEORGIA	TESTIMONY REV REQMT
UNITED GAS PIPELINE COMPANY	DOCKET NO. RS-92-26000	F.E.R.C.	ASSISTED COUNSEL
UNITED CITIES GAS COMPANY	DOCKET NO. 4188-U	GEORGIA	TESTIMONY REV REQMT

TESTIMONY OF THOMAS J. PRISCO
BEFORE REGULATORY AGENCIES
1989 TO PRESENT

COMPANY	PROCEEDING	JURISDICTION	ACTION & SUBJECT
EL PASO ELECTRIC COMPANY	DOCKET NO. 12700	TEXAS	TESTIMONY REV REQMT
NIAGARA MOHAWK POWER CORPORATION	CASE NOS. 94-E-0098 94-E-0099, 94-E-0100	NEW YORK	REV REQMT PRICE CAPS
ENERGY POLICY ACT OF 1992 SEC 115 CONSERVATION EFFORTS BY GAS UTILITIES	DOCKET NO. 93-730-G	SOUTH CAROLINA	TESTIMONY DSM
WHEELING & LAKE ERIE RWY ABANDONMENT	DOCKET NO. AB-227 (Sub-No. 2X)	I.C.C.	ASSISTED COUNSEL
INVESTIGATION OF SELF GENERATION AND ECONOMIC INCENTIVE RATES	DOCKET NO. E100, (Sub 73)	NORTH CAROLINA	TESTIMONY RATE DESIGN
INVESTIGATION INTO ELECTRIC POWER COMPETITION	DOCKET NO. I 94=0032	PENNSYLVANIA	TESTIMONY
RECOVERY OF STRANDED COSTS BY PUBLIC AND TRANSMITTING UTILITIES	DOCKET NO. RM 94-007-000	F.E.R.C.	TESTIMONY
INVESTIGATION OF ELECTRIC SERVICE COMPETITION AND REGULATORY POLICIES	CASE NO. 8678	MARYLAND	TESTIMONY
ALTERNATIVE POWER POOLING INSTITUTIONS	DOCKET NO. RM 94-20-000	F.E.R.C.	TESTIMONY
ECONOMIC DEVELOPMENT INCENTIVE POLICY (GAS, ELECTRIC, TELEPHONE)	DOCKET NO. 4697-U	GEORGIA	TESTIMONY RATE DESIGN

General Services Administration
Public Buildings Service
Washington, DC 20405

FEB 15 1995

The Honorable William J. Perry
Secretary of Defense
Washington, DC 20301

Dear Mr. Secretary:

By letter dated January 17, 1995, to the Assistant Commissioner, Office of Procurement, General Services Administration, Robert N. Kittel, Chief, Regulatory Law Office, Office of the Judge Advocate General, Department of the Army, requested the enclosed delegation of authority.

The delegation is made to the Secretary of Defense in accordance with section 205(d) of the Federal Property and Administrative Services Act of 1949, as amended (40 U.S.C. 486(d)), which provides that the Administrator of General Services may make such a delegation to the head of any other Federal agency.

The delegation of authority authorizes the Secretary of Defense to represent the consumer interests of the executive agencies of the Federal Government, consistent with Administration policy, in proceedings before the Pennsylvania Public Utility Commission concerning Pennsylvania Power and Light Company's request for an increase in electric rates, Docket No. R 94-3271.

We understand that the Department of the Army, Office of the Judge Advocate General, will perform the functions being delegated to the Secretary of Defense by the enclosed delegation of authority, and that the Office of General Counsel, General Services Administration, will be kept fully advised of the progress of the proceeding.

Sincerely,

ROBERT A. DILUCHIO
Assistant Commissioner for
Governmentwide Real Property Policy

Enclosure

cc: Honorable Togo D. West, Jr.
Secretary of the Army
Washington, DC 20310

Robert N. Kittel
Chief, Regulatory Law Office
901 North Stuart Street
Arlington, VA 22203-1837

GENERAL SERVICES ADMINISTRATION
PUBLIC BUILDINGS SERVICE

D - 95-06

DELEGATION OF AUTHORITY TO THE SECRETARY OF DEFENSE

1. Purpose. This delegation authorizes the Secretary of Defense to represent the consumer interests of the executive agencies of the Federal Government in proceedings before the Pennsylvania Public Utility Commission.

2. Effective date. This delegation is effective immediately.

3. Delegation.

a. Pursuant to the authority vested in the Administrator of General Services by sections 201(a)(4) and 205(d) of the Federal Property and Administrative Services Act of 1949, as amended (40 U.S.C. 481(a)(4) and 486(d)), authority is delegated to the Secretary of Defense to represent the consumer interests of the executive agencies of the Federal Government in proceedings before the Pennsylvania Public Utility Commission concerning Pennsylvania Power and Light Company's request for an increase in electric rates, Docket No. R 94-3271.

b. The Secretary of Defense may redelegate this authority to any officer, official, or employee of the Department of Defense.

c. This authority shall be exercised in accordance with Administration policy and the policies, procedures, and controls prescribed by the General Services Administration (GSA), and shall be exercised in cooperation with the responsible officers, officials, and employees thereof.

d. This authority will expire 2 years from the date of issuance.

Dated: FEB 15 1995

ROBERT J. DILUCHIO
Assistant Commissioner for
Governmentwide Real Property Policy

USAGE AT SELECTED MILITARY FACILITIES
SERVED UNDER RATE LP-5

BILL MONTH	FACILITY	KWH USAGE	BILLING PEAK KW USAGE	DAYS	MONTHLY BILLING	RATE
10/93	SCRANTON AAP	2,284,000	5731	32	$145,925.00	LP5
11/93	SCRANTON AAP	2,166,000	5357	29	137,752.61	LP5
12/93	SCRANTON AAP	2,440,000	6278	29	156,943.46	LP5
1/94	SCRANTON AAP	2,452,000	5904	32	154,562.78	LP5
2/94	SCRANTON AAP	2,638,000	6173	31	164,792.36	LP5
3/94	SCRANTON AAP	2,724,000	6163	29	168,303.80	LP5
4/94	SCRANTON AAP	2,694,000	5933	32	165,056.12	LP5
5/94	SCRANTON AAP	2,444,000	5933	30	152,761.45	LP5
6/94	SCRANTON AAP	2,084,000	5170	29	129,809.11	LP5
7/94	SCRANTON AAP	2,181,000	5098	32	115,239.66	LP5
8/94	SCRANTON AAP	2,073,000	5486	30	113,508.40	LP5
9/94	SCRANTON AAP	2,124,000	5357	29	114,301.30	LP5
			ANNUAL TOTAL		$1,718,956.05	

BILL MONTH	FACILITY	KWH USAGE	BILLING PEAK KW USAGE	DAYS	MONTHLY BILLING	RATE
10/93	TOBYHANNA AD	2,963,000	7523	30	$179,761.83	LP5
11/93	TOBYHANNA AD	2,727,000	7212	29	170,080.97	LP5
12/93	TOBYHANNA AD	3,059,000	7517	31	182,396.32	LP5
1/94	TOBYHANNA AD	3,306,000	7867	30	193,883.03	LP5
2/94	TOBYHANNA AD	3,606,000	8042	33	204,560.85	LP5
3/94	TOBYHANNA AD	3,317,000	8191	29	200,853.92	LP5
4/94	TOBYHANNA AD	3,380,000	8061	30	198,383.80	LP5
5/94	TOBYHANNA AD	3,520,000	7834	32	200,521.54	LP5
6/94	TOBYHANNA AD	2,985,000	7601	29	176,702.05	LP5
7/94	TOBYHANNA AD	3,037,000	7951	30	181,990.85	LP5
8/94	TOBYHANNA AD	3,309,000	8106	32	193,679.42	LP5
9/94	TOBYHANNA AD	3,265,000	8256	29	190,640.79	LP5
			ANNUAL TOTAL		$,2,273,455.37	

USAGE AT SELECTED MILITARY FACILITIES
SERVED UNDER RATE LP-5

BILL MONTH	FACILITY*	KWH USAGE	BILLING PEAK KW USAGE	DAYS	MONTHLY BILLING	RATE
10/93	CARLISLE BKS	2,020,800	4344	30	$122,895.45	LP5
11/93	CARLISLE BKS	1,562,400	3959	29	100,083.07	LP5
12/93	CARLISLE BKS	1,584,000	3080	29	93,536.37	LP5
1/94	CARLISLE BKS	1,718,400	3275	32	100,902.39	LP5
2/94	CARLISLE BKS	1,548,000	3004	31	91,358.94	LP5
3/94	CARLISLE BKS	1,600,800	3046	31	93,955.15	LP5
4/94	CARLISLE BKS	1,569,600	2989	30	92,144.30	LP5
5/94	CARLISLE BKS	1,632,000	3264	30	96,459.50	LP5
6/94	CARLISLE BKS	1,896,000	3665	31	109,179.49	LP5
7/94	CARLISLE BKS	2,055,000	4981	30	126,997.48	LP5
8/94	CARLISLE BKS	2,450,000	5219	30	145,132.63	LP5
9/94	CARLISLE BKS	2,447,000	4890	31	142,044.13	LP5
				ANNUAL TOTAL	$1,314,688.90	

* Carlisle Barracks has a much smaller electric service billing under rate LP-4, also.

BILL MONTH	FACILITY	KWH USAGE	BILLING PEAK KW USAGE	DAYS	MONTHLY BILLING	RATE
10/93	NEW CUMBERLAND AD	4,632,000	9716	32	$255,987.00	LP5
11/93	NEW CUMBERLAND AD	3,546,000	9318	29	221,314.69	LP5
12/93	NEW CUMBERLAND AD	3,426,000	7605	29	203,849.84	LP5
1/94	NEW CUMBERLAND AD	3,638,400	7115	32	209,509.65	LP5
2/94	NEW CUMBERLAND AD	3,511,200	7258	31	205,915.59	LP5
3/94	NEW CUMBERLAND AD	3,423,600	7335	29	207,379.96	LP5
4/94	NEW CUMBERLAND AD	3,856,800	7420	32	218,613.72	LP5
5/94	NEW CUMBERLAND AD	3,570,000	7379	30	208,628.63	LP5
6/94	NEW CUMBERLAND AD	3,450,800	8020	29	203,512.92	LP5
7/94	NEW CUMBERLAND AD	4,006,800	9398	32	231,729.45	LP5
8/94	NEW CUMBERLAND AD	4,446,400	9996	30	252,571.85	LP5
9/94	NEW CUMBERLAND AD	4,209,600	9582	29	242,343.60	LP5
				ANNUAL TOTAL	$2,661,356.98	

GRAND TOTAL FOR SELECTED MILITARY INSTALLATIONS $7,968,457.30

DOD ADJUSTMENTS TO OPERATING INCOME EXHIBIT TJP-4
PPUC JURISDICIONAL PRO FORMA AT PRESENT AND PROPOSED RATES
YEAR ENDING SEPTEMBER 30, 1995
(Thousands of Dollars)

LINE NO.		PP&L PROPOSED RATES	DOD ADJUSTMENTS	ADJUSTED AT PRESENT RATES	ADJUSTMENT TO RATE INCREASE	DOD PROPOSED PRO FORMA RATES
1.	Operating Revenues	$2,663,890		$2,663,890	($183,436)	$2,480,454
	Operating Expenses					
2.	Operation and Maintenance	1,372,927	(64,817)	1,308,110		1,308,110
3.	Depreciation	320,797	(61,000)	259,797		259,797
4.	Regulatory Debits/Credits	(29,208)		(29,208)		(29,208)
	Provision for Taxes					
5.	Taxes Other Than Income	199,897	6,417	206,314	(9,356)	196,958
	Income Taxes					
6.	Federal Tax	231,952	37,197	269,149	(54,232)	214,917
7.	State Tax	81,765	13,122	94,887	(19,131)	75,756
8.	Deferred Income Taxes	(15,424)		(15,424)		(15,424)
9.	Investment Tax Credit	(8,625)		(8,625)		(8,625)
10.	Total Taxes	489,565	56,736	546,301	(82,719)	463,582
11.	Gain from Disposition of Emmission All	(466)	0	(466)		($466)
12.	Total Operating Expenses	2,153,615	(69,081)	2,084,534	(82,719)	2,001,815
13.	Operating Income	$510,275	$69,081	$579,356	($100,717)	$478,639

PENNSYLVANIA POWER AND LIGHT COMPANY

EXHIBIT TJP-5

ADJUSTMENT TO RATE CASE EXPENSE
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.	DESCRIPTION	AMOUNT
1	PP&L PROPOSED NORMALIZED ADJUSTMENT	($745)
2	TOTAL RATE CASE EXPENSES	$1,491
3	DOD PROPOSED THREE YEAR AVERAGE	$497
4	LESS: PPUC RATE CASE EXPENSE PER BUDGET	1,491
5	DOD PROPOSED DECREASE	($994)
6	DOD ADJUSTMENT TO RATE FILING	($249)

PENNSYLVANIA POWER AND LIGHT COMPANY EXHIBIT TJP-6

ADJUSTMENT TO INTEREST ON CUSTOMER DEPOSITS
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.	DESCRIPTION	AMOUNT
1	COMPANY PROPOSED	$122
2	CUSTOMER DEPOSITS	$1,106
3	INTEREST RATE	7.5%
4	DOD PROPOSED INTEREST	$83
5	DOD ADJUSTMENT (Ln 4 - Ln 1)	($39)

EXHIBIT TJP-7

PENNSYLVANIA POWER AND LIGHT COMPANY

ADJUSTMENT FOR VOLUNTARY EARLY RETIREMENT PROGRAM (VERP)
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.			AMOUNT
1	COMPANY PROPOSED		($13,917)
2	ESTIMATED COST OF THE VERP	$65,800	
3	AMORTIZATION OVER FIVE YEARS		$13,160
4	DOD PROPOSED VERP WAGE SAVINGS		
5	AVERAGE MONTHLY WAGE PER EMPLOYEE	$4.5	
6	ANNUAL PAY PER EMPLOYEE (Ln 5 * 12)	$54.3	
7	PARTICIPANTS NOT PREVIOUSLY COUNTED	580	
8	DOD PROPOSED VERP WAGE SAVINGS	($31,480)	
9	WAGES TO EXPENSE (Ln 8 * 73.3%)		($23,075)
10	BENEFITS	($10,500)	
11	BENEFITS TO EXPENSE (Ln 10 * 68.7%)		($7,213)
12	DOD PROPOSED VERP SAVINGS		($17,128)
13	DOD ADJUSTMENT (Ln 12 - Ln 1)		($3,211)

PENNSYLVANIA POWER AND LIGHT COMPANY EXHIBIT TJP-8

ADJUSTMENT TO DECOMMISSION FOSSIL UNITS
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.		AMOUNT
1	COMPANY PROPOSED	$52,818
2	DOD PROPOSED	$0
3	DOD ADJUSTMENT (Ln 2 - Ln 1)	($52,818)

PENNSYLVANIA POWER AND LIGHT COMPANY EXHIBIT TJP-9

ADJUSTMENT TO ANNUAL ACCRUAL FOR DECOMMISSIONING EXPENSE
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.		AMOUNT
1	COMPANY PROPOSED INCREASE	$22,916
2	AMOUNT PER BUDGET	7,126
3	TOTAL COMPANY PROPOSED	$30,042
4	DOD PROPOSED INCREASE	$0
5	AMOUNT PER BUDGET	7,126
6	TOTAL DOD	$7,126
7	DOD ADJUSTMENT (Ln 6 - Ln 3)	($22,916)

EXHIBIT TJP-10

PENNSYLVANIA POWER AND LIGHT COMPANY

ADJUSTMENT TO SHORTEN FOSSIL PLANT
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.		AMOUNT
1	COMPANY PROPOSED INCREASE (COMPANY ATTACHMENT A, EXHIBIT FUTURE 1)	$28,000
2	DOD PROPOSED	0
3	DOD ADJUSTMENT	($28,000)

PENNSYLVANIA POWER AND LIGHT COMPANY EXHIBIT TJP-11

ADJUSTMENT TO LEVELIZE SUSQUEHANNA SINKING FUND DEPRECIATION
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.		AMOUNT
1	COMPANY PROPOSED INCREASE (COMPANY ATTACHMENT A, EXHIBIT FUTURE 1)	$33,000
2	DOD PROPOSED	0
3	DOD ADJUSTMENT	($33,000)

PENNSYLVANIA POWER AND LIGHT COMPANY

EXHIBIT TJP-12

RATE OF RETURN AT
YEAR ENDED SEPTEMBER 30, 1995

Line NO.		CAPITALIZATION RATIO	EMBEDDED COST	RETURN
1	LONG-TERM DEBT	46.53%	7.97%	3.71%
2	PREFERRED STOCK	7.59	7.31	0.55%
3	DOD PROPOSED	45.88	11.5%	5.28%
4	TOTAL	100%		9.54%

PENNSYLVANIA POWER AND LIGHT COMPANY EXHIBIT TJP-13

MEASURES OF VALUE AND RATE OF RETURN
YEAR ENDED SEPTEMBER 30, 1995

Line NO.		
1	COMPANY MEASURE OF VALUE (NET)	$5,017,178
2	PRO FORMA RETURN AT ADJUSTED RATES	
3	PERCENT	9.54%
4	AMOUNT	$478,639

PENNSYLVANIA POWER AND LIGHT COMPANY — EXHIBIT TJP-14

ADJUSTMENT TO RATE CASE EXPENSE
YEAR ENDED SEPTEMBER 30, 1995
(Thousands of Dollars)

Line NO.		AMOUNT
1	OPERATION AND MAINTENANCE ADJUSTMENTS	($64,817)
2	DEPRECIATION ADJUSTMENTS	($61,000)
3	TOTAL OPERATING EXPENSE ADJUSTMENT	($125,817)
4	TAXES OTHER THAN INCOME ADJUSTMENT	$6,417
5	INCOME TAXES	
6	FEDERAL	$37,197
7	STATE	$13,122
8	TOTAL TAXES	$56,736

AFFIDAVIT OF THOMAS J. PRISCO

COUNTY OF ARLINGTON)
) SS:
COMMONWEALTH OF VIRGINIA)

I, Thomas J. Prisco, Staff Accountant, U.S. Army Legal Services Agency, depose and say under oath that the foregoing direct testimony and exhibits were prepared by me or under my direct supervision and control; I have knowledge of the matters set forth in said testimony and exhibits; and that such matters are true and correct to the best of my knowledge, information, and belief.

Thomas J. Prisco

Subscribed and sworn to before me this 6th day of April, 1995, in the County of Arlington, Commonwealth of Virginia.

Notary Public

My Commission Expires: Mar 30, 1995

CERTIFICATE OF SERVICE

I certify that I have caused a copy of the foregoing testimony and exhibits to be sent this day, by OVER-NIGHT delivery to counsel for ACTIVE PARTIES, and by postage prepaid, first class U.S. Mail to the other addressees:

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Dated this 6th day of April 1995, at Arlington County, Virginia.

David A. McCormick

DOCUMENT FOLDER

OTS Statement No. 1 & Exh No. 1
Witness: K. L. Deardorff
Date: April 14, 1995

4/27/95
Hbg
jaw

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

Pennsylvania Power & Light Company

Docket No. R-00943271

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INFO. CONTROL DIV.

Direct Testimony

of

Kevan L. Deardorff

DOCKETED
APR 28 1995

Concerning:

Fair Rate of Return

PENNSYLVANIA POWER & LIGHT COMPANY
Docket No. R-00943271

Direct Testimony of
Kevan L. Deardorff

TABLE OF CONTENTS

Q. Please state your name and business address.

A. My name is Kevan L. Deardorff. My business address is P.O. Box 3265, Harrisburg, Pa., 17105-3265.

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

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Finance Section of the Telecommunications/Water Division in the Office of Trial Staff as an expert witness in the area of rate of return. The Finance Section addresses financial matters for all utility types within the Office of Trial Staff.

Q. What is your educational and professional background?

A. I have prepared this information in Appendix A supplementing my direct testimony.

I. Subject of Testimony

Q. Define the issues that are addressed in this testimony.

A. The issues addressed in my direct testimony are recommendations concerning rate of return, including capital structure, the embedded cost of debt, the cost of preferred stock, the cost of common equity and the overall fair rate of return which Pennsylvania Power & Light Company (PP&L) should be allowed the opportunity to earn during the period that rates will be in effect.

Q. Does your direct testimony include an exhibit that supports your recommended fair rate of return?

A. Yes. OTS Exhibit No. 1 includes schedules which summarize my recommended overall fair rate of return and presents the financial data and economic factors employed in my analysis. The exhibit was prepared by me or under my supervision.

II. Background Discussion

Q. How does the rate of return component fit within the revenue requirement formula?

A. The revenue requirement formula is as follows:

$$RR = E + d + T + (V-D) \times R$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expense
d	=	Depreciation Expense
T	=	Taxes
V	=	Gross Rate Base
D	=	Accrued Depreciation
R	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage of the rate base. The calculation of that rate is independent of the rate base determination. Therefore, the dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. What constitutes a fair and reasonable overall rate of return?

A. A fair and reasonable overall rate of return is one which will allow the utility the opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period its rates will be in effect.

The Bluefield Water Works and Hope Natural Gas cases of 1923 and 1944, respectively, set forth the following principles that are generally accepted by regulators as the proper criteria for measuring a fair rate of return:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable

> at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia, 262 U.S. 679, 692-93 (1923).

> It is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with risks on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

While interpretations of these quotations may vary somewhat, they do provide general guidelines for the regulator to determine a fair rate of return.

Q. Would you please explain how you calculated your overall rate of return?

A. Yes. The overall rate of return in this rate proceeding is calculated using the weighted average cost of capital method, which is the interaction of the following components: the percentage of debt, the percentage of preferred stock, the percentage of common equity, the cost of debt, the cost of preferred stock, and the rate of return on common equity. First, it is necessary to determine the proportion of each type of capital (referred to as the capital structure) which has financed the rate base and assign the appropriate cost rate to each. The capital structure may be actual or imputed if the actual capital structure is not representative of the industry norm. The cost rates of debt and preferred stock are fixed and can be computed accurately. The rate of return on common equity is not fixed and is much more difficult to measure.

The overall rate of return is then calculated using the proportions of each type of capital and the cost rates of each type of capital. On OTS Exhibit No. 1, Schedule 1, I demonstrate the interaction of the capital structure and the cost rates of each type of capital. By multiplying each capital component's capital ratio by its associated cost rate, a weighted cost rate is derived for each capital component. The overall rate of return is the sum of weighted cost rates.

III. Company Position

A. Summary

Q. What is the Company's rate of return claim in this case?

A. Mr. Paul R. Moul, the Company's witness, recommended the following rate of return for the Pennsylvania Power & Light Company (PP&L Exhibit PRM-1, Schedule 14):

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	46.53	7.97	3.71
Preferred Stock	7.59	7.31	0.55
Common Equity	45.88	13.00	5.96
Total	100.00		10.22

B. Basis

Q. Please state the basis for the Company's claims?

A. On page 30 of his testimony (PP&L Statement 12), Mr. Moul stated that his recommended capitalization ratios of 46.53 percent long-term debt, 7.59 percent preferred stock, and 45.88 percent common equity are estimated for PP&L as of September 30, 1995. The computation of these ratios is shown on PP&L Exhibit PRM-1, Schedule 4.

On page 31 of his testimony, Mr. Moul stated that the related long-term debt cost rate is 7.97 percent at September 30, 1995. PP&L Exhibit PRM-1, Schedule 5, Page 2, lists the issues of debt expected to be outstanding and the computation of the average embedded debt cost rate for the period ending September 30, 1995.

On page 32 of his testimony, Mr. Moul stated that he calculated an embedded cost rate of preferred stock to be 7.31 percent for the future test year. PP&L Exhibit PRM-1, Schedule 6, Page 2, lists the issues of preferred stock expected to be outstanding and the computation of the average embedded cost rate for the preferred stock at September 30, 1995.

Mr. Moul stated on page 33 of PP&L Statement 12 that he used four methodologies to determine his 13.00 percent common equity cost rate. These methods are the Discounted Cash Flow model, the Risk Premium analysis, the Capital Asset Pricing Model, and the Comparable Earnings approach. The greatest portion of Mr. Moul's testimony and exhibit concerns the determination of the cost of common equity.

IV. OTS Position

A. Summary

Q. Will you please state your recommendation?

A. Yes. The following is a summary of my rate of return recommendation:

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	46.53	7.97	3.71
Preferred Stock	7.59	7.31	0.55
Common Equity	45.88	*10.63*	*4.88*
Total	100.00		*9.14*

B. Elements Adopted

Q. Have you adopted any elements of the Company's recommendation in arriving at your position?

A. Yes. I have adopted the Company's recommended capital structure and cost rates of long-term debt and preferred stock.

C. Elements Disputed

Q. How does your recommendation differ from the Company's claim.

A. In the table above, I have italicized the numbers where my recommendation differs from the Company's rate of return claim. My recommendation differs in one area, the proper rate of return on common equity. I recommend a rate of return on common equity of 10.63 percent in lieu of Mr. Moul's 13.00 percent recommendation. As a result my overall rate of return recommendation is 9.14 percent as opposed to Mr. Moul's 10.22 percent recommendation. Therefore, the sole issue in this case concerning rate of return is the cost of common equity.

V. Capital Structure

Q. Would you please define capital structure and discuss its significance in public utility ratemaking?

A. Capital Structure is a percentage expression of the permanent long-term financing of a company. Typically[1] this permanent financing is represented by long-term debt, preferred stock, and common equity[2]. To calculate a company's capital structure, the dollar amount of each capital class is divided by the dollar amount of the total capital.

In public utility ratemaking, a company's capital structure is used to determine the weighted average cost of capital (also called "overall" rate of return). The use of a company's permanent capital to compute its capital

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[1]These are the three most common classes of capital. There are other less common classes of capital, such as capital leases and minority interest which sometimes finance a utility's rate base.

[2]Common equity, also called "net worth", consists of capital stock, capital in excess of par value and retained earnings.

structure assumes that the rate base is financed entirely with this capital. However, short-term debt must be included in the capital structure calculation when it is used to finance rate base components.

Q. What standards are used to determine whether a capital structure is acceptable for ratemaking purposes?

A. There are two standards that are generally accepted in the determination of whether a capital structure is acceptable for ratemaking purposes. First, if a company raises all of its own fixed capital (debt and preferred stock), its capital structure is used. In the instance where a parent company provides the fixed capital, the parent company's capital structure is used in place of the company's capital structure.

The second standard is that the capital structure should be representative of the industry norm. The use of a capital structure that is significantly outside the range of the industry's capital structure may result in an overstated overall rate of return. In that instance, a hypothetical capital structure based upon industry average should be used for ratemaking purposes.

Q. In the situation where a company's recommended capital structure is near the extremes of the industry range, is it appropriate to adjust the rate of return.

A. Yes. As previously stated, an inefficient capital structure can produce an overstated overall rate of return. Under normal circumstances, common equity capital is assigned a higher cost rate than debt. Debt is less expensive and interest on debt is tax deductible. Therefore, a capital structure too heavily weighted with common equity will require higher revenues not only for the extra return required for an excessive common equity ratio, but also for the additional revenue requirement due to higher taxes[3]. For that reason, care must be taken to insure that the capital structure used for ratemaking purposes is well-balanced insofar that it takes reasonable advantage of leverage[4]. This is not to say that a capital structure should be too heavily weighted with debt. As the percentage of debt goes up, financial risk increases, interest coverages declines and bond ratings may be reduced. Consequently, the incremental savings from the increased use of debt is more than offset by the higher cost rates for all classes of capital. Of course, as financial risk increases beyond a

[3]Taxes will be higher because the tax deduction for interest is lower.

[4]Leverage is defined as the amount of additional debt and preferred stock in the capital structure. Leverage is used to enhance the rate of return on common equity. This opportunity for higher earnings growth, however, is not risk free. The trade-off is an increase in financial risk.

reasonable level, a utility's ability to raise the necessary capital for plant improvements and general corporate purposes is jeopardized.

Q. What capital structure do you recommend in this proceeding?

A. I recommend the adoption of Respondent's recommended capital structure which consists of 46.53 percent long-term debt, 7.59 percent preferred stock, and 45.88 percent common equity. This capital structure is presented on Schedule 1.

Q. What is the basis for your adoption of the Company's recommended test year-end capital structure?

A. For comparison purposes, I have presented capital structure ratios for Pennsylvania Power & Light Company and Mr. Moul's barometer group of electric companies in OTS Exhibit No. 1, Schedule 2, page 1. The barometer group's debt ratios for 1994 and estimated for 1995 are 45.89 and 45.25 perce-nt, respectively, compared to PP&L's claimed debt ratio at 9/30/95 of 46.53 percent. PP&L's debt ratio is .64 percentage point higher than the barometer group's historical debt ratio and 1.28 percentage points higher than the barometer group's projected debt ratio indicating slightly higher financial risk.

In addition, using the ten-year range of common equity ratios shown on OTS Exhibit No. 1, Schedule No. 2, page 2 as a guide, PP&L's 45.88 percent common equity ratio is near the top end of the range of 42.66 to 45.37 percent for the barometer group.

Overall, it is clear that the differential in financial risk is negligible.

VI. Cost of Debt

Q. What analysis led to your adoption of PP&L's 7.97 Percent cost rate of long-term debt?

A. The embedded cost rates of debt for the eight-company electric barometer group at 12/31/93 are in the range of 5.18 to 7.99 percent. PP&L's 7.97 percent recommended cost rate of long-term debt is within that range.

VII. Cost of Preferred Stock

Q. What analysis led to your adoption of PP&L's 7.31 Percent cost rate of preferred stock?

A. The embedded cost rates of preferred stock for the eight-company electric barometer group at 12/31/93 are in the range of 5.81 and 7.84 percent. PP&L's 7.31 percent recommended cost rate of preferred stock fits well within that range.

VIII. Rate of Return on Common Equity

A. Basis for Determining Rate of Return on Equity

Q. What is the basis for determining a rate of return on common equity?

A. Comprehensive financial analysis will produce a rate of return on common equity within a range of reasonableness. The determination of a rate of return on common equity within that range requires the analyst to exercise informed judgement based on financial and investors' expectations during various segments of the business cycle. The marketplace must be consulted for some insight into a rate of return on common equity since investors determine the price at which common equity capital will be provided.

The determination of the rate of return on common equity also requires the review of historic and current financial and economic data as well as prospective estimates of inflation rates, interest rates, and the state of our economy in general. A proper matching of these cost indicators to the current and expected phase of the business cycle is necessary in order to provide a rate of return on common equity recommendation which will allow the utility an opportunity to earn a satisfactory, but not excessive, return. Management's efficient pursuit of earning that return will preserve its financial soundness. As a result the Company will be able to compete for new capital in the marketplace with companies of comparable risk.

B. Methodology Used

Q. What method have you utilized in your rate of return on common equity determination?

A. I have employed the discounted cash flow method (DCF) in determining a reasonable rate of return on common equity for PP&L in this proceeding. I have applied this method to current market data for PP&L and Mr. Moul's barometer group of eight electric companies. My final recommendation will be based on giving equal weighting to the results for both PP&L and the barometer group.

Q. What factors influenced you to give significant weight to the results for PP&L?

A. PP&L's only business, currently, is the production and sale of electricity. PP&L'S management has assured its investors that any future diversification will be concentrated in the energy and allied businesses with which they have experience. PP&L has adequate financial and market data available to use in a DCF analysis.

Q. Why have you not used PP&L as your only source of financial data in the analysis?

A. I have chosen to use a barometer group as an additional source of information for two reasons. The use of data for one company may be less reliable than using a barometer group because the data for one company may be subject to events which can cause short-term aberrations in the marketplace. The rate of return on common equity for a single company could become distorted in these particular circumstances. The use of a barometer group has the effect of smoothing out any aberrations associated with using a single company.

A barometer group of companies is also used as a benchmark to satisfy the long established regulatory guideline of providing a utility the opportunity to earn a return equal to that of similar risk enterprises.

<u>C. Barometer Group Selection</u>

Q. What barometer group have you chosen for your return of equity analysis?

A. I adopted Mr. Moul's barometer group of electric companies. The six common characteristics of the barometer group companies are appropriate selection criteria.

D. Economic Factors

Q. Does your return on equity analysis take changing business and economic conditions into account?

A. Yes. The financial markets take all factors into account when assessing investments. The aggregate risks of an investment are reflected in the stock price per share. The barometer group data that I have utilized is market based; therefore, my results have accounted for all these factors.

Q. What economic factors do you consider important in your analysis of cost of capital?

A. I have made comparisons of important economic variables and have examined their impact on electric utilities over the past twenty years. Schedule 3, of my exhibit, presents a historical perspective of the Moody's "A" Utility Bond Yield, the U.S. T-Bills rate, the prime interest rate, and the percent change in the CPI compared to the average dividend yield of my barometer group for the same period. This schedule also presents a sampling of economic experts' quarterly forecasts for 1995 and 1996 and yearly forecasts for the period 1996 to 2005.

Q. Is there a relationship between dividend yields of electric companies and bond yields?

A. Yes. A comparison of the bond yields and dividend yields in Schedule 3 reveals a direct relationship between these two variables. I think it's important in determining an appropriate rate of return on common equity to recognize this relationship. Any potential impact related to a projected change in bond yields should be considered in recommending a representative dividend yield for the prospective period. In general these bond and dividend yields were in a relatively narrow range over the past nine years.

Q. What is the outlook for interest rates in relation to the inflation rate?

A. Schedule No. 3, of Exhibit No. 1 also presents short-term and long-term forecasts published by Blue Chip Financial Forecasts. Forecasting professionals are expecting Treasury Bill (T-Bill) yields to be in a range of 6.0 to 6.5 percent (Blue Chip Financial Forecasts - Quarterly forecasts) and forecasted inflation to be between 3.2 to 3.5 percent over the next two years. As a result the real rate of interest is expected to be in the two to three percent range. The longer-term trend for the T-Bill and inflation forecasts is downward. Forecasting professionals are expecting T-Bills to peak at 6.5 percent and begin a decline to 5.5 percent over the next five years. Similarly, inflation is expected to decline from a high of 3.5 percent to 3.3 percent over the same five year period. As a result the real rate of interest is expected to remain within the equilibrium range of two to three percent.

Forecasting professionals are also expecting interest rates on long-term "A" rated utility bonds to increase slightly from the current level of 8.5 percent to 8.8 percent and then fall back to 8.5 percent over the next year. These forecasts are dependent upon forecasters' belief that investors expect a slow down in the economy with real GDP growth declining from a 4.5 percent growth rate in the fourth quarter of 1994 to 2.2 percent in the first quarter of 1996.

Investors' expectations are, however, continually changing and influenced by Federal Reserve policy. The Federal Reserve's tight monetary policy of recent years has done much to alleviate inflationary fear. If the Federal Reserve continues to maintain their current anti-inflationary bias in monetary policy and manages to attain their interest rate and monetary targets, investors' inflationary expectations will continue to decrease resulting in lower and more stable interest rates.

Q. What evidence exists that interest rates will continue to decline in the longer-term future?

A. Schedule 3 of OTS Exhibit No. 1 also presents extended forecasts for the various interest rates presented. Forecasters are expecting the yields on Moody's "A" Utility Bonds to peak in the second quarter of 1995 at 8.8 percent and then decline to a level in the range of 8.0 to 8.2 percent over the next ten-years.

Q. What impact will lower inflation and interest rates have on utility companies?

A. Lower inflation and interest rates will lower a utility's investment risk with a resultant lower cost of capital. Investment risk consists of business risk and financial risk. Utilities are generally considered to have less business risk than industrial firms primarily because of the inherent advantages monopolies have over competitive enterprises.

Financial risk is attributable to the amount and cost rate of debt employed in a capital structure. Debt and preferred stock carry contractual guarantees which must be met before a return can be paid to the common stockholder. Management will normally utilize a capital structure which maximizes its long-term profit potential while maintaining its financial safety. Utilities have historically utilized more leverage than their industrial counterparts resulting in a relatively higher level of financial risk. Because of the greater degree of leverage employed, utility bonds have historically carried a higher cost rate than the same grade of industrial bonds.

Q. Currently, are the utilities' debt cost rates still higher than the cost rates on the same grade of industrial bonds?

A. Yes. But the spread between the two has been narrowing. In 1983, the spread between "A" rated utility bonds and "A" rated industrial bonds was 56 basis points. For the period 1993 to 1994, this spread has been averaging about 5 basis points.

Q. What has caused this spread to narrow?

A. The utility industry, being highly capital intensive, is very sensitive to the economic conditions in the capital markets resulting from historically high inflation and interest rates. During the past inflationary period the overall investment risk of public utilities increased relative to non-regulated firms due to the increased financial risk resulting from very high and volatile interest rates. As a result the spread between the yields on utility and industrial bonds increased during this inflationary period. In September and October of 1981, interest rates peaked and began a long-term downtrend. As a result, overall investment risk began to decline and the spread narrowed.

Assuming inflation and long-term interest rates continue in a long-term downtrend or remain stable, I believe the overall investment risk of public utilities will decline further and lead to a lower cost of capital to utilities in relation to their industrial counterparts.

E. Discounted Cash Flow Analysis (DCF)

Q. Will you please explain your DCF method of analysis?

A. My analysis employs the standard discrete DCF model, $k = D_1/P_0 + g$, where D_1 is the dividend expected during the year, P_0 is the current price of the stock, and g is the expected growth rate of dividends. For purposes of calculating a dividend yield applicable to the formula, D_0/P_0 (the current dividend divided by the current price) must be adjusted by ½ the expected growth rate[5] in order to account for changes in the dividend rate in period 1.

In theory, the DCF method advocates the use of the most-current dividend yield. For purposes of ratemaking, a dividend yield that is representative of the prospective period when new rates will be in effect must be determined. Ratemaking is essentially a forward looking, as well as a long-run, process. An analysis cannot be based solely on short-term spot market data. Investors are continually changing their opinions concerning the relative worth of debt and equity on a monthly, weekly, or even a daily basis, based on changes in the economy or the financial position of a company. A spot rate of return which may seem appropriate for current ratemaking purposes may be too

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[5]The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain. It could occur next month or the twelfth month. On average it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by ½ the expected growth rate is appropriate.

high or too low at a later point in time depending upon changing economic conditions in the marketplace.

Conversely, longer-run average data avoids problems associated with short-run aberrations, but runs the risk of being characterized as "stale" data. This problem becomes very pronounced especially during periods of distinct trends (either up or down).

A regulator setting rates for a future period must make a "best" judgment concerning representative stock prices and dividend rates. With regard to a "best" judgment, I have chosen to utilize dividend yields calculated using current spot prices and 52 week averages.

Q. Please state the results of your discounted cash flow (DCF) analysis and an explanation of how you arrived at those results.

A. The following table summarizes the results of my DCF analysis (see Pages 1 and 2, of OTS Exhibit No. 1, Schedule No. 4).

	Range	Average
Eight Company Barometer Group	10.30 - 10.50%	10.40%
Pennsylvania Power & Light Co.	10.43 - 10.90%	10.67%

As a check on the reasonableness of these ranges, I also performed a DCF analysis using forecasted dividend yields and growth rates (see bottom of

Schedule 4, page 3, of OTS Exhibit No. 1). Value Line projects the adjusted dividend yield for the barometer group to average 6.81 percent five years into the future and a growth rate of 2.44 percent for the five-year forecast period. Based upon Value Line's dividend yield and dividend growth rate projections the DCF expected rate of return five years from now would be 9.25 percent for the barometer group. For PP&L the DCF expected rate of return five years from now would be 9.40 percent. These results suggest that Value Line expects rates of return to continue to decline over the next three-to-five years for these electric companies.

Q. Are the primary DCF results reliable given the current general market conditions?

A. Yes. The DCF results are grounded on two assumptions concerning general market conditions. These assumptions are that (1) the payout ratio will remain constant and (2) price/earnings ratios will remain constant. Both assumptions are required in a constant growth DCF model so that both the dividend yield and the growth rate can be assigned specific values.

Q. Please discuss the first assumption with respect to the reliability of the DCF results.

A. The first assumption is that the payout ratio will remain reasonably constant so that the rate of dividend growth will closely follow the growth rate of earnings per share. OTS Exhibit No. 1, Schedule No. 4, Page 4 presents the historical and forecasted payout ratios for the barometer group and PP&L. While over relatively short periods of time the payout ratios display some volatility, over the longer-term there has been a tendency for it to revert to the mean. If investors are relatively confident that payout ratios are mean reverting then they can expect the rate of growth of dividend and earnings to be similar over the long-run.

The following summarizes investors' expectations with respect to payout ratios for the barometer group and PP&L:

	Range for 1986-1994	Mean	1994	Forecast
Barometer Group	68.85-95.11	81.75	84.72	79.25
PP&L	70.44-91.26	78.92	91.26	81.40

Q. Please discuss the second assumption with respect to the reliability of the DCF results.

A. The second assumption is that the price/earnings ratio will remain the same from time of purchase to time of sale. I am not contending the P/E ratio will be the same for the prospective period. However, for cost of capital purposes in a rate-making context, I must make this strict assumption. Otherwise a specific estimate of a rate of return for the prospective period would be much more complex.

Evidence of investor expectations of stable P/E ratios is presented in OTS Exhibit No. 1, Schedule 4, Page 5. For the barometer group the P/E ratios on average are expected to increase slightly over the next five years from 11.2 to 11.8. For PP&L, the P/E ratio is expected to decline from 12.4 to 10.5 over the next five years.

Q. What dividend yield did you use in your DCF analysis?

A. A representative ratemaking dividend yield must be calculated over a time frame that avoids the problems of short-term aberrations and "stale" data series. For purposes of my DCF analysis, I have placed equal emphasis on the most recent spot and 52 week average dividend yields. The following table summarizes my dividend yield computations for the barometer group and PP&L.

	Dividend Yields (Adjusted) Spot 2/22/95 (%)	Dividend Yields (Adjusted) 52-week Average (%)
Barometer Group	7.30	7.50
PP&L	8.15	7.68

Source: OTS Exhibit No. 1, Schedule 4, pp. 1-2.

Q. Please explain why you did not present a separate calculation for a growth adjustment to your dividend yield.

A. In this case, the dividends used in the dividend yield calculations are Value Line's projected dividends (D_1) which reflect a full years growth. Therefore, the standard growth rate adjustment that I discussed on page 21 is not necessary in this analysis.

Q. What information did you rely upon to determine your expected growth rate?

A. To arrive at a representative dividend growth rate for the prospective period, I surveyed several series of both projected growth rates and historical growth rates. These growth rates are presented in OTS Exhibit No. 1, Schedule No. 4, Page 6. My growth rate estimates are based on a survey of Value Line estimates, Standard & Poor's consensus estimates, internal and external growth rates, ten-year log-linear dividend growth rates, and 12-month dividends and earnings growth rates.

Q. What factors determine the importance of analysts' growth rate forecasts in your determination of an overall growth rate?

A. The availability of data is an important consideration in any analysis of investors' expectations. As a source of growth rates, Value Line provides an abundance of information including projected and historical growth rates. Sufficient data is available from Value Line to calculate expected internal and external growth rates. In addition, Value Line has a very wide circulation and is easily available to individual investors. Individual investors comprise the bulk of electric utility ownership. According to the Standard & Poor's Stock Guide (S & P), March, 1995, individual investors own 67.99 percent of the shares of the electric companies in the barometer group and 77.11 percent of the shares of PP&L.

S & P, on the other hand, has more limited data availability. S & P reports a consensus of projected earnings growth rates for some of the barometer group companies, but not projections of dividend growth rates. However, S & P does have the advantage of surveying more than one analyst for each company.

Q. How are log-linear growth rates determined?

A. The ten-year log-linear growth rates are derived from a linear regression of log-transformed dividends using time as the independent variable. The log-transformation is necessary because the dividends, earnings, and price times series data for electric companies is non-linear with respect to time. Regression analysis requires that the data be in a linear form. The log-transformation essentially straightens the data into a linear form.

Q. How are the internal and external growth rates derived?

A. The internal and external growth rates for the barometer group and PP&L are developed in OTS Exhibit No. 1, Schedule No. 4, page 7. The internal growth rate is the result of the product of the expected retention rate (b) and the expected earned rate of return (r). A company realizes this growth by reinvesting retained earnings back into the company. External growth is the product of the expected issuance rate for new common stock share (s) and the expected accruals (v). A company realizes this growth by issuing new common stock at a price above current book equity.

Q. Which growth elements in OTS exhibit No. 1, Schedule No. 4, Page 6, are the most relevant in your determination of the prospective growth rate?

A. I have arranged the columns in OTS Exhibit No. 1, Schedule No. 4, page 6 in order of the importance in determining a representative growth rate. Under normal circumstances I would give primary weight to expected growth rates in comparison to historical growth rates simply because more information is implicitly contained in these estimates. The bulk of the research evidence has indicated analysts' growth forecasts to be superior to historically-oriented growth measures in forecasting growth. Forecasting professionals have already accounted for historical data in their estimates along with expectations of a wide array of economic variables. To give significant weight to historical growth rates would result in a double count.

Q. What do you conclude to be a reasonable growth rate for the barometer group?

A. Based upon the results presented in OTS Exhibit No. 1, Schedule No. 4, page 6, I conclude that investors could reasonably expect to achieve a growth rate of 2.75 to 3.25 percent for the barometer group.

Q. What leads you to believe that investors should expect to achieve a growth rate of 2.75 to 3.25 percent for the barometer group?

A. The forecasted growth rates for the barometer group are 1.4 percent for dividends, 2.66 percent for the internal and external growth estimate, and 3.0 percent for earnings ((3.4+2.63)/2). The average growth from these three variables is 2.35 percent. While normally I would give significant and equal weight to these three variables in my final growth rate recommendation it is quite apparent that the expected dividend growth rates are forecasted to be set temporarily low. Value Line in the most recent issue suggests that electric utilities are in the process of lower payout ratios for several reasons. Among these reasons are slowdown in earnings, future funds needed for compliance to Phase 2 of the Clean Air Act, and future funds needed for new capacity. As a result, I chose to give primary weight to forecasted earnings and historical dividend growth.

The range of growth rates for these variables is from 2.3 percent to 3.4 percent. From these results I conclude that a more narrow range of 2.75 to 3.25 percent is appropriate for the barometer group.

Q. What do you conclude to be a reasonable growth rate for PP&L?

A. Based upon the results presented in OTS Exhibit No. 1, Schedule No. 4, page 4, I conclude that investors could reasonably expect to achieve a growth rate of 2.50 to 3.00 percent for PP&L.

Q. What leads you to believe that investors should expect to achieve a growth rate of 2.50 to 3.00 percent for PP&L?

A. PP&L is in the same situation as the rest of the barometer group companies. Similarly, little weight should be given to forecasted dividend growth.

The growth rates for forecasted earnings and historical dividends range from 1.0 to 3.5 percent. Based on these growth rates, I believe that a more narrow growth rate range of 2.50 to 3.00 percent is appropriate for PP&L.

Q. What rate of return on common equity is indicated from the results of your DCF analysis?

A. Given these representative dividend yields and using the midpoint of the growth rate ranges, I applied the DCF formula with the results presented in Schedule No. 4, Pages 1 and 2 and summarized on page 22 of this testimony. Based upon these DCF results, I believe that 10.25 to 11.00 percent represents a reasonable rate of return on common equity for a electric utility. My recommendation for PP&L in this proceeding is 10.63 percent, which is the midpoint of the range.

F. Investment Risk Adjustment

Q. Have you made any adjustment for investment risk?

A. No. Based upon the risk indicators I have examined in this case, I conclude that there are no significant differences in risk between PP&L and the barometer group.

Q. What risk indicators have you examined.

A. I have examined the financial risk and business risk indicators as well as the total investment risk indicators presented in the Company's direct testimony.

Q. How is PP&L's financial risk in comparison to the barometer group?

A. As I explained earlier on page 12 of my testimony, PP&L has a negligible financial risk differential in comparison to the barometer group.

Q. How is PP&L's business risk in comparison to the barometer group?

A. Based upon the business risk indicators presented by the Company, PP&L at this point in time, has less business risk in comparison to the barometer group.

Mr. Moul presented seven indicators of business risk (PP&L Statement 12, pages 22-26). Only one ratio (dividend yield) indicated higher risk. Five categories (Coefficient of variation, operating ratio, coverage ratio, quality of earnings, and internally generated funds) indicated less business risk for PP&L in comparison to the barometer group.

Q. What was the result of your examination of the total investment risk indicators?

A. This examination indicated that there is conflicting evidence presented by Mr. Moul regarding the differences in total investment risk between PP&L and the barometer group. The Company witness presented a comparison of betas as an indicator of differences in total investment risk between PP&L and the barometer group (Exhibit PRM-1, Schedule 13, Page 1). The betas reported for Merrill Lynch indicated PP&L has more investment risk while the betas reported for Value Line indicated PP&L has less investment risk.

G. Market Pressure, Selling and Issuance Expense

Q. Have you taken into consideration market pressure and selling and issuance expenses in making your recommendation?

A. Yes. I believe that market pressure and selling and issuance expenses are an additional cost of capital that are incurred at the time of issuance. However, the current market price of common stock already reflects these items, as investors have already capitalized market pressure and issuance expenses in determining the value of the stock at the time of purchase. Since my analyses are market based, these items have already been taken into consideration. As a result I have made no additional adjustments to account for Market pressure and issuance expenses.

IX. Overall Weighted Cost of Capital

Q. What is your overall weighted cost of capital for PP&L?

A. OTS Exhibit No. 1, Schedule No. 5 presents the calculation of PP&L's overall weighted cost of capital. My recommended rate of return on common equity results in an overall weighted cost of capital of 9.14 percent.

X. Pre-tax Interest Coverage

Q. Have you tested the interest coverage of your overall rate of return recommendation?

A. Yes. I have presented interest coverage calculations in OTS Exhibit No. 1, Schedule No. 5. My recommendation will provide PP&L an opportunity to achieve a pre-tax interest coverage of 3.52 times. On Schedule No. 6 of Exhibit No. 1, I have presented results of an analysis of experienced interest coverages for the period of 1984 to 1993 for the barometer group and PP&L. The following is a summary of those experienced interest coverages:

	Range for 1984-1993	Mean	1994
Barometer Group	2.33 - 3.33	3.00	3.05
PP&L	1.54 - 3.33	2.77	3.33

Pre-tax interest coverage of 3.52 times exceeds the ten-year range of coverages for the barometer group and PP&L.

Q. How does 3.52 times interest coverage compare to recent S&P's benchmarks for electric utilities?

A. The S&P pre-tax interest coverage benchmarks for an "A" rating for an electric company ranges between 2.75 for an above average business position and 4.50 for a below average business position. PP&L's calculated interest coverage of 3.52 meets the target set by S&P of 3.5 for an average business position.

Q. What conclusion have you drawn from your coverage analysis regarding the fairness of your overall rate of return recommendation?

A. The results of my coverage analysis indicate that my overall rate of return recommendation of 9.14 percent is fair and reasonable. It also indicates that Mr. Moul's 10.22 percent overall rate of return recommendation which produces 4.03 times coverage is excessive.

XI. Critique of PP&L's Cost of Capital Testimony

Q. Please summarize your critique of PP&L's proposed cost of capital testimony.

A. I have two primary areas of disagreément concerning Mr. Moul's cost of capital testimony and his resultant rate of return recommendation.

- First, Mr. Moul's has made several serious errors in his DCF analysis.
- Second, Mr. Moul has incorrectly given weight to the Comparable Earnings, Risk Premium and CAPM models.

Q. Please explain the specific errors Mr. Moul made in his DCF analysis.

A. Mr. Moul was able to inflate his DCF results by making an unwarranted ex-dividend adjustment to his dividend yields and an unwarranted .5 percent upward adjustment to his growth rates to reflect market factors.

Q. Why should the ex-dividend adjustment be rejected as appropriate adjustment to the DCF returns?

A. I find this to be an inappropriate adjustment for two reasons. First, Mr. Moul was unable to supply any academic evidence in support of an ex-dividend adjustment to dividend yields in the context of the DCF analysis.

Secondly, Mr. Moul was unable to provide any investor influencing financial publication that provides ex-dividend adjusted dividend yields to investors for their investment decision making purposes.

Q. Why should Mr. Moul's .5 percent adjustment to his growth rate be rejected?

A. The .5 percent adjustment to account for market factors should be rejected for two reasons. First, it is my opinion that Mr. Moul's growth estimate of 3.5 percent already accounts for this information. In making his 3.5 percent estimate, Mr. Moul has relied upon analysts projections as they appear on Schedule 10, Pages 1 and 2 of Exhibit PRM-1. Analysts projections are based upon not only company specific information but market factors such as those listed by Mr. Moul on page 43 of Statement 12. The addition of the .5 percent to his 3.5 percent growth rate is therefore a double count.

Q. What is the second reason the .5 percent adjustment should be rejected?

A. Mr. Moul has not presented any quantitative evidence to support the claim that the market factors result in an additional .5 percent growth to the company. Mr. Moul acknowledged on cross examination that these factors could result in a negative adjustment. Without sufficient quantitative evidence to support a specific number this adjustment should be rejected.

Q. Mr. Moul believes that the risk premium and CAPM results should be given significant weight along with the DCF results. Why should these methods be rejected for ratemaking purposes?

A. To understand why these methods should be rejected for ratemaking purposes, it must first be understood how investors use these methods. The risk premium model (RP) and the Capital Asset Pricing Model (CAPM) are relevant to investors in their investment decision making process, but the relevancy does not carry over to the ratemaking process. The RP and CAPM methods give results that indicate to an investor what the equity cost rate should be if current economic conditions are the same as those present during the historical period risk premiums were determined. By comparing RP and CAPM results with current expected equity returns (DCF results), an investor can make rational buy and sell decisions.

When expected DCF returns are higher than those indicated by the RP and CAPM historical norms an investor would have an incentive to buy, and vice versa.

The relevancy of these methods does not carry over to the ratemaking process because we can never be certain that the economic conditions underlying the historical period during which the risk premiums were calculated are the same as today or in the future. Mr. Moul's risk premium is based on the Ibbotson & Associates study which goes back 65 years. This period included economic conditions of inflation in excess of 12 percent and "A" rated utility bonds yields in excess of 17.0 percent as well as other unusual economic scenarios. At present those conditions do not exist; nor are they expected to recur in the near future.

Q. Given the fact that economic conditions today are different from the historical period, how does this affect the risk premiums used in Mr. Moul's RP and CAPM models?

A. The RP and CAPM models do not measure the current rate of return on common equity directly as does the DCF model. These methods determine the rate of return on common equity by indirectly observing the current cost of debt. An implicit assumption when using these methods is that the variables determining the equity cost rate and debt cost rate are the same, which allows the analyst to apply a constant risk premium. Actually, the variables determining the cost rates in the two markets are different. Changing economic conditions cause these variables in the two markets to change resulting in changing risk premiums over time. Therefore, the use of a constant risk premium fails to capture the effect of changing economic conditions over time.

Q. Is there any current academic evidence that examines the credibility of the CAPM model?

A. Yes. OTS Exhibit No. 1, Schedule 9, presents an article which appeared in the New York Times on February 18, 1992, that summarizes a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French. Their study examined the importance of beta (CAPM's risk factor) in explaining returns on common stock. In CAPM theory, the higher a stock's beta the higher the expected return on that stock. They found that the model did not do well in predicting actual returns. As a result of this new information, I believe that rational investors will give less credibility to expected equity returns that are calculated using the simple CAPM model.

Q. Mr. Moul also believes that the comparable earnings results should be given some weight. Why should this method be rejected for ratemaking purposes?

A. Mr. Moul's comparable earnings method merely computes historical book returns for unregulated companies. I believe it is more appropriate to determine a cost of capital by using expectational models such as the DCF model rather than a model based on historical data. Similarly, I believe it more appropriate to assess market returns of companies in the same industry rather than book returns of companies that are dissimilar.

Q. Can you provide an analysis that demonstrates that Mr. Moul's unregulated companies are viewed quite differently than PP&L?

A. Yes. Please turn to OTS Exhibit No. 1, Schedule 8 where I have provided a comparison of the debt to total capital ratio and the percent of institutional holdings of the unregulated companies used in Mr. Moul's Comparable Earnings analysis to the Barometer Group of Eight Electric Companies and PP&L. The average debt ratio for Mr. Moul's unregulated companies is 21 percent, compared to 46 percent for the eight electric companies and 49 percent for PP&L. Institutional investors hold 52.8 percent of the shares of the unregulated companies compared to 29.7 percent for the eight electric companies and 21.0 percent for PP&L. Clearly, institutional investors view the unregulated companies used in Mr. Moul's Comparable Earnings analysis differently than they do the electric companies.

Q. Does this complete your testimony?

A. Yes, it does.

APPENDIX A

Kevan L. Deardorff

Educational and Professional Background

I am a graduate of the Pennsylvania State University, where I received a Bachelor of Science Degree in Business Economics and Finance and a Master of Arts Degree in Economics. Before coming to the Pennsylvania PUC in 1983, I worked as a consultant for the United States Environmental Protection Agency between 1980 and 1981, and as a Research Economist for the Pennsylvania Department of Commerce during 1982.

I am currently employed as a Fixed Utility Financial Analyst III. I have completed rate of return analyses in a number of electric rate cases and assisted in the analyses of many electric, gas, water and telephone rate cases. I have presented testimony before the Pennsylvania Public Utility Commission in the following rate cases:

Keystone Water Company	R-822211-12 R-822215-19 R-822221
Western Pennsylvania Water Company	R-832381
Philadelphia Suburban Water Company	R-842592
Duquesne Light Company	R-842583
Western Pennsylvania Water Company	R-842621-25
Riverton Consolidated Water Company	R-842675
Keystone Water Company	R-842755-56 R-842759
Equitable Gas Company	R-842769
Western Pennsylvania Water Company	R-850096-97
West Penn Power Company	R-850220
Dauphin Consolidated Water Supply Co.	R-860350
Western Pennsylvania Water Company	R-860397

Philadelphia Electric Company (Gas Division)	R-870629
National Fuel Gas Distribution Corp.	R-870719
Western Pennsylvania Water Company	R-870825
Philadelphia Suburban Water Company	R-870840
Equitable Gas Company	R-880971
Chartiers Natural Gas Company	R-891283
Columbia Gas of Pennsylvania, Inc.	R-891468
Arrowhead Public Service Corp.	R-891557
Pennsylvania-American Water Co.	R-901652
Citizens Utilities Water Company of Pennsylvania	R-901663
Citizens Utilities Home Water Company	R-901664
National Fuel Gas Distribution	R-901670
York Water Company	R-901813
Columbia Gas of Pennsylvania, Inc.	R-901873
National Fuel Gas Distribution Corp.	R-911912
The Peoples Natural Gas Company	R-00922180
York Water Company	R-00922168
Pennsylvania & Southern Gas Company	R-00922312
North Penn Gas Company	R-00922276
North East Heat and Light Company	R-00922309

Shenango Valley Water Company	R-00922420
Mechanicsburg Water Company	R-00922502
National Fuel Gas Distribution Corp.	R-00932548
Roaring Creek Water Company	R-00932665
Shenango Valley Water Company	R-00932798
The Peoples Natural Gas Company	R-00932866
Blue Mountain Consolidated Water Co.	R-00932873
Allied Gas Company, et. al.	R-00932952
National Fuel Gas Distribution Corp.	R-00942991
Borough of Media Water Works	R-00943098
Newtown Artesian Water Company	R-00943157
Roaring Creek Water Company	R-00943177
Borough of Schuylkill Haven	R-00943156

OTS Exhibit No. 1
Witness: K. L. Deardorff
Date: April 14, 1995

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

Pennsylvania Power & Light Company

Docket No. R-00943271

Schedules To Accompany Direct Testimony

of

Kevan L. Deardorff

Concerning:

Fair Rate of Return

OTS Exhibit No. 1

Index to Schedules

Schedule	Title
1	Pennsylvania Power & Light Company - Weighted Cost of Capital Conclusion.
2 Page 1	Capitalization Ratios for the Pennsylvania Power & Light Company Compared to the Barometer Group of Eight Electric Companies.
2 Page 2	Common Equity Ratios for the Pennsylvania Power & Light Company and the Barometer Group of Eight Electric Companies for 1984-1993
3	Comparison of Key Economic Variables to the Dividend Yields for the Pennsylvania Power & Light Company and the Barometer Group of Eight Electric Companies for 1975 to 1994 and Estimates for 1995 to 2005.
4 Page 1	Expected Market Rate of Return on Equity Using Data for the Eight Company Barometer Group.
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4 Page 3	Value Line Expected Market Rate of Return on Equity for the Period 1998 to 2000 Using Data for the Pennsylvania Power & Light Company and the Barometer Group of Eight Electric Companies
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4 Page 5	Current and Expected Price/Earnings Ratios for the Barometer Group of Eight Electric Companies and the Pennsylvania Power & Light Company at February, 1995.
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4 Page 7	Expected Internal and External Growth Rates for the Barometer Group of Eight Electric Companies and Pennsylvania Power & Light Company at March, 1995.
5	Pennsylvania Power & Light Company - Interest Coverage
6	Historical Interest Coverage Ratios for the Barometer Group of Eight Electric Companies and the Pennsylvania Power & Light Company for 1984-1993.

7 A Study Shakes Confidence In the Volatile-Stock Theory.

8 Comparison of Debt to Total Capital and Percent Institutional for Mr. Moul's Comparable Earnings Barometer Group Compared to the Barometer Group of Eight Electric Companies and the Pennsylvania Power & Light Company at March 1, 1995

Summary of Findings and Recommendations

1) Pennsylvania Power & Light Company
Capital Structure (Recommended):

a)	Long Term Debt	46.53%
b)	Preferred Stock	7.59%
c)	Common Equity	45.88%

2) Pennsylvania Power & Light Company
Cost Rates of Capital Components (Recommended):

a)	Long Term Debt	7.97%
b)	Preferred Stock	7.31%
c)	Common Equity	10.63%

3) Inflation Rate Forecast

a)	CPI - (1995-96)	3.2 - 3.5%

4) Equity Cost Rate Indicators

		DCF
a)	Eight Company Barometer Group	10.30 - 10.50%
b)	Pennsylvania Power & Light Company	10.43 - 10.90%

5) Pre and Post-tax Interest Coverage
(based on 10.63% return on equity)

a)	Pre-tax (1)	3.52
b)	Post-tax	2.46

6) Overall Weighted Cost of Capital for Pennsylvania Power & Light Company

a)	Original Cost	9.14%

Notes: (1) Assumes an effective tax rate of 42.14%.

Pennsylvania Power & Light Company
Weighted Cost of Capital Conclusion

		(1)	(2)	(3)
		Capital Structure	Cost Rates	Weighted Cost of Capital
(1)	Long-Term Debt	46.53%	7.97%	3.71%
(2)	Preferred Stock	7.59%	7.31%	0.55%
(3)	Common Equity	45.88%	10.25 - 11.00%	4.70 - 5.05%
(4)	Total	100.00%		8.96 - 9.31%
(5)	Conclusion		10.63%	9.14%

Capitalization Ratios for the Pennsylvania Power & Light Company
Compared to the Barometer Group of Eight Electric Companies

		(1)	(2)	(3)	(4)	(5)
		PP&L	Barometer Group	PP&L	Barometer Group	PP&L
		(9/30/94)	(12/31/94)	(9/30/95)	(12/31/95)	(12/31/95)
(1)	Long-Term Debt	47.13%	45.89%	46.53%	45.25%	47.00%
(2)	Preferred Stock	7.90%	7.16%	7.59%	7.00%	8.00%
(3)	Common Equity	44.96%	46.95%	45.88%	47.75%	45.00%
(4)	Total	100.00%	100.00%	100.00%	100.00%	100.00%

Sources: Company provided data
Value Line Investment Survey, January 13, and March 17, 1995
Standard & Poor's Compustat Data Base

Common Equity Ratios for the Pennsylvania Power & Light Company
and the Barometer Group of Eight Electric Companies for 1984-1993

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Company	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
(1) Allegheny Power System, Inc.	40.57	40.21	42.52	43.67	45.12	46.15	46.08	45.56	45.05	46.12
(2) American Electric Power Company	36.66	38.03	38.44	38.06	39.78	44.74	42.31	42.67	40.96	41.08
(3) Atlantic Energy, Inc.	46.19	46.84	42.68	44.64	45.16	46.09	45.35	47.07	46.52	44.93
(4) Baltimore Gas & Electric Company	45.60	46.48	49.07	48.35	46.51	43.79	43.18	42.13	46.28	43.71
(5) Delmarva Power & Light Company	43.22	42.89	43.17	44.20	46.18	44.58	40.32	43.02	42.97	48.17
(6) DPL Inc.	41.30	39.36	39.81	41.06	42.28	46.74	48.39	48.75	48.22	45.80
(7) Potomac Electric Power Company	43.35	43.99	48.69	48.82	42.71	44.12	38.50	38.79	39.94	40.36
(8) Public Service Enterprise Group	44.40	49.50	47.47	50.02	46.97	46.72	46.42	44.74	46.34	46.57
(9) Barometer Group Average	42.66	43.41	43.98	44.85	44.34	45.37	43.82	44.09	44.54	44.59
(10) Pennsylvania Power & Light Company	33.13	33.66	33.70	35.58	36.49	37.81	40.50	40.59	41.52	42.41

Sources: Standard and Poor's Compustat Data Base

OTS Exhibit No. 1
Schedule No. 3

Comparison of Key Economic Variables to the Dividend Yields
for the Pennsylvania Power and Light Company
and the Barometer Group of Eight Electric Companies
for 1975 to 1994 and Estimates for 1995 to 2005

		(1)	(2)	(3)	(4)	(5)	(6)
						Dividend Yield	
	Year	Moody's 'A' Utility Bond Yield	U.S. Treasury Bills	Prime Rate	CPI Percent Change	PP&L	Electric Group
(1)	1975	10.09	5.84	7.86	7.00	10.11	10.39
(2)	1976	9.29	4.99	6.84	4.80	8.65	8.53
(3)	1977	8.61	5.27	6.83	6.80	8.11	8.11
(4)	1978	9.29	7.22	9.06	9.00	8.88	9.21
(5)	1979	10.49	10.04	12.67	13.30	10.44	10.52
(6)	1980	13.34	11.51	15.27	12.50	12.00	12.19
(7)	1981	15.95	14.03	18.87	8.90	13.34	12.74
(8)	1982	15.86	10.69	14.86	3.80	11.99	11.41
(9)	1983	13.66	8.63	10.79	3.80	10.70	10.46
(10)	1984	14.03	9.58	12.04	4.00	10.90	10.68
(11)	1985	12.46	7.48	9.93	3.80	9.68	8.93
(12)	1986	9.58	5.98	8.33	1.10	7.24	6.83
(13)	1987	10.09	5.82	8.21	4.40	7.60	7.29
(14)	1988	10.49	6.69	9.32	4.40	7.72	7.76
(15)	1989	9.77	8.12	10.87	4.60	7.35	7.59
(16)	1990	9.86	7.51	10.01	6.10	7.08	7.92
(17)	1991	9.36	5.42	8.46	3.10	6.51	7.60
(18)	1992	8.69	3.45	6.25	2.90	6.09	6.85
(19)	1993	7.59	3.02	6.00	2.70	5.73	6.29
(20)	1994	8.30	4.29	7.15	2.70	7.28	7.22
	Recent Forecasts:						
(21)	1995-1st Qtr	8.70	6.00	8.90	3.20		
(22)	1995-2nd Qtr	8.80	6.30	9.20	3.30		
(23)	1995-3rd Qtr	8.70	6.40	9.40	3.40		
(24)	1995-4th Qtr	8.70	6.50	9.40	3.50		
(25)	1996-1st Qtr	8.50	6.40	9.30	3.50		
	Extended Forecasts:						
(26)	1996	8.40	6.10	8.90	3.50		
(27)	1997	8.00	6.00	8.50	3.40		
(27)	1998	8.10	5.40	8.10	3.30		
(28)	1999	8.00	5.30	7.90	3.20		
(29)	2000	8.20	5.50	8.10	3.30		
(30)	2000-05	8.10	5.30	8.00	3.20		

Sources: Economic Indicators, January, 1995
Blue Chip Financial Forecasts, March 1, 1995
Moody's Bond Record, March, 1995
Standard & Poor's Compustat Data base

Expected Market Rate of Return on Equity
Using Data for the Eight Company Barometer Group

	Time Period	(1) Adjusted Dividend Yield for Barometer Group (1) (%)	(2) Estimated Long-Term Growth Rate for the Barometer Group (%)	(3) Expected Rate of Return for the Barometer Group (%)
(1)	52 Week Average (ending 2/95)	7.50	3.00	10.50
(2)	Spot Price(2) (ending 2/95)	7.30	3.00	10.30
(3)	Average:			10.40

Notes: (1) Value Line's reported dividends are projected for the year ahead.
(2) Value Line reports the spot price on the last Wednesday of the month.

Sources: Value Line-Value Screen Data Base, March 1, 1995

Expected Market Rate of Return on Equity
Using Data for the Pennyslvania Power & Light Company

	Time Period	(1) Adjusted Dividend Yield for PP&L (1) (%)	(2) Estimated Long-Term Growth Rate for PP&L (%)	(3) Expected Rate of Return for PP&L (%)
(1)	52 Week Average (ending 2/95)	7.68	2.75	10.43
(2)	Spot Price(2) (ending 2/95)	8.15	2.75	10.90
(3)	Average:			10.67

Notes: (1) Value Line's reported dividends are projected for the year ahead.
(2) Value Line reports the spot price on the last Wednesday of the month.

Sources: Value Line-Value Screen Data Base, March 1, 1995

Value Line Expected Market Rate of Return on Equity
for the Period 1998 to 2000
using Data for the Pennyslvania Power & Light Company
and the Barometer Group of Eight Electric Companies

		(1) Value Line Projected Dividend Yield (%)	(2) Value Line Projected Growth Rate(1) (%)	(3) Value Line Projected Rate of Return (%)
(1)	Eight Company Barometer Group	6.81	2.44	9.25
(2)	Pennsylvania Power & Light Company	7.40	2.00	9.40

Notes: (1) The projected growth rate is an average of Value Line's five-year estimated growth for earnings, dividends, and book value.

Sources: Value Line Investment Survey, January 13, and March 17, 1995

Dividend Payout Ratios for the Pennsylvania Power & Light Company
and the Barometer Group of Eight Electric Companies for 1986-1994
and Five Year Forecasts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Company	1986	1987	1988	1989	1990	1991	1992	1993	1994	5-Year Forecast
(1) Allegheny Power System, Inc.	70.79	72.91	76.26	83.33	87.29	87.85	87.98	86.70	85.86	77.33
(2) American Electric Power Company	86.26	79.05	72.22	72.62	86.64	88.89	94.49	88.89	88.56	76.31
(3) Atlantic Energy, Inc.	74.86	67.33	74.46	76.47	97.35	85.71	100.00	85.56	86.52	82.05
(4) Baltimore Gas & Electric Company	56.67	54.11	65.02	99.29	100.00	92.11	87.73	79.46	75.50	70.83
(5) Delmarva Power & Light Company	70.10	89.38	86.47	83.89	103.36	106.94	104.05	87.50	92.22	86.49
(6) DPL Inc.	65.44	57.50	71.64	68.97	69.80	93.91	80.60	78.87	78.67	81.18
(7) Potomac Electric Power Company	57.28	61.61	64.49	67.59	93.83	83.42	96.39	84.10	92.74	83.90
(8) Public Service Enterprise Group	69.40	78.04	78.21	78.24	81.64	87.65	109.64	79.70	77.70	75.93
(9) Barometer Group Average	68.85	69.99	73.60	78.80	89.99	90.81	95.11	83.85	84.72	79.25
						Average for 1986-94			81.75	
(10) Pennsylvania Power & Light Company	83.23	80.72	73.80	70.44	75.25	77.11	78.71	79.71	91.26	81.40
						Average for 1986-94			78.92	

Sources: Value Line Investment Survey, January 13, and March 17, 1995

Current and Expected Price/Earnings Ratios
for the Barometer Group of Eight Electric Companies
and the Pennsylvania Power & Light Company at February, 1995

	Company	(1) Current P/E	(2) Five Year Forecasted P/E
(1)	Allegheny Power System, Inc.	11.1	12.22
(2)	American Electric Power Co., Inc.	12.3	11.54
(3)	Atlantic Energy, Inc.	10.7	12.82
(4)	Baltimore Gas & Electric Company	11.3	11.46
(5)	Delmarva Power & Light Company	11.0	13.51
(6)	DPL Inc.	12.8	12.65
(7)	Potomac Electric Power Company	10.5	10.98
(8)	Public Service Enterprise Group, Inc	10.0	9.32
(9)	Eight Company Average	11.2	11.81
(10)	Pennsylvania Power & Light Company	12.4	10.47

Sources: Value Line Investment Survey, January 13, and March 17, 1995

Actual and Estimated Growth Rates for the Barometer Group of Eight Electric Companies
and the Pennsylvania Power & Light Company at March, 1995

		Expected Growth				Historical Growth			
			Earnings			Dividends			
	Company	Value Line Five Year Dividend Growth Estimates	Internal & External Five Year Estimates	Value Line Five Year Growth Estimates	S & P	Ten Year Log-Linear	Value Line Five Year Compounded	Current Twelve Month Growth	Current 12 Month Earnings Growth
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Allegheny Power System	1.0	2.97	3.0	2.00	2.19	1.5	.00	-1.06
(2)	American Electric Power Company	.5	3.34	3.5	2.00	0.73	.5	.00	41.15
(3)	Atlantic Energy, Inc.	.5	2.19	2.0	2.00	2.37	2.5	.00	-21.67
(4)	Baltimore Gas & Electric Company	3.0	3.46	6.5	4.00	3.52	2.5	2.70	4.32
(5)	Delmarva Power & Light Company	.5	1.62	3.0	2.00	3.06	1.5	.00	-5.11
(6)	DPL Inc.	4.0	2.95	4.5	4.00	2.22	3.5	5.08	8.45
(7)	Potomac Electric Power Company	1.0	1.93	2.0	2.00	5.35	4.5	.00	-9.14
(8)	Public Service Enterprise Group	.5	2.78	3.0	3.00	1.81	1.5	.00	12.10
(9)	Eight Company Barometer Group	1.4	2.66	3.4	2.63	2.66	2.3	.97	3.63
(10)	Pennsylvania Power & Light Company	1.5	2.24	1.0	2.00	3.23	3.5	.00	-31.88

Sources: Value Line Investment Survey, January 13, and March 17, 1995
Standard and Poor's Stock Guides
Standard and Poor's Earnings Guide, March, 1995

Expected Internal and External Growth Rates
for the Barometer Group of Eight Electric Companies
and Pennsylvania Power & Light Company at March, 1995

	Company	(1) Expected Retention Rate (b)	(2) Expected Roe (r)	(3) Expected Share Growth (s)	(4) Expected Accruals (v)	(5) Combined Growth (br + sv)
(1)	Allegheny Power System	0.227	11.5	1.28	0.285	2.97
(2)	American Electric Power Company	0.262	12.5	0.24	0.303	3.34
(3)	Atlantic Energy, Inc.	0.179	11.5	0.38	0.320	2.19
(4)	Baltimore Gas & Electric Company	0.292	11.0	1.22	0.205	3.46
(5)	Delmarva Power & Light Company	0.135	11.5	0.18	0.362	1.62
(6)	DPL Inc.	0.188	14.5	0.49	0.449	2.95
(7)	Potomac Electric Power Company	0.161	11.5	0.39	0.204	1.93
(8)	Public Service Enterprise Group	0.241	11.5	0.10	0.084	2.78
(9)	Eight Company Barometer Group					2.65
(10)	Pennsylvania Power & Light Company	0.186	11.0	1.56	0.124	2.24

Note: b = Expected retention rate, or 1-(D/E).
v = the proportion of the increment of the expected price to the per share bookvalue that accrues to or dilutes the per share earnings of the existing shareholder, or 1-(B/P).
D = Dividend.
E = Earnings.
B = Book Value.
P = Price.

Sources: Value Line Investment Survey, January 13, 1995 and March 17, 1995

OTS Exhibit No. 1
Schedule No. 5

Pennsylvania Power & Light Company
Interest Coverage

		(1) Capital Structure	(2) Cost Rates	(3) Weighted Cost of Capital	(4) Effective Tax Rate Compliment(1)	(5) Pre-tax Weighted Cost Rates
(1)	Long Term Debt	46.53%	7.97%	3.71%		3.71%
(2)	Preferred Stock	7.59%	7.31%	0.55%	0.5786	0.96%
(3)	Common Equity	45.88%	10.25 - 11.00%	4.70 - 5.05%	0.5786	8.13 - 8.72%
(4)	Total	100.00%		8.96 - 9.31%		12.80 - 13.39%
(5)	Conclusion		10.63%	9.14%		13.09%

(6) Pre-Tax Coverage: 13.09/3.71 = 3.52

(7) After-Tax Coverage: 9.14/3.71 = 2.46

Notes: (1) Effective income tax rate assumed to be 42.14%.
[35% Fed. Inc. Tax +(10.99% State Inc. Tax x (1-.35))].

Historical Interest Coverage Ratios for the Barometer Group of Eight Electric Companies and the Pennsylvania Power & Light Company for 1984-1993

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Company	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
(1)	Allegheny Power System, Inc.	3.36	3.02	3.94	3.63	3.37	3.14	3.14	3.19	3.05	3.03
(2)	American Electric Power Company	1.89	2.25	2.40	2.22	2.30	2.43	2.43	2.59	2.56	2.45
(3)	Atlantic Energy, Inc.	3.20	2.92	2.44	3.57	2.87	3.02	2.80	3.39	3.58	3.51
(4)	Baltimore Gas & Electric Company	3.87	4.09	4.20	4.36	3.62	2.75	1.27	2.00	2.46	2.81
(5)	Delmarva Power & Light Company	4.48	4.47	3.73	3.17	3.17	2.87	1.80	2.59	3.05	3.59
(6)	DPL Inc.	1.93	1.39	3.36	1.61	2.50	2.19	2.19	2.70	3.30	3.32
(7)	Potomac Electric Power Company	4.25	4.51	4.65	4.55	3.71	3.52	2.48	2.72	2.72	2.92
(8)	Public Service Enterprise Group	2.92	2.91	1.89	3.36	3.05	2.79	2.53	2.57	2.45	2.79
(9)	Barometer Group Average	3.24	3.20	3.33	3.31	3.07	2.84	2.33	2.72	2.90	3.05
								Ten Year Average			3.00
(10)	Pennsylvania Power & Light Company	1.54	2.48	2.81	2.75	2.68	2.85	2.94	3.14	3.18	3.33
								Ten Year Average			2.77

Sources: Standard and Poor's Compustat Data Base

N.Y. Times Tue. Feb 18, 1992

OTS Exhibit No. 1
Schedule No. 7

Market Place

A Study Shakes Confidence In the Volatile-Stock Theory

By ERIC N. BERG

One of the most enduring ideas of modern finance is facing its most serious challenge. Two scholars of finance say they have disproved the theory, common among investors, that stocks more volatile than the market as a whole are the best performers.

Eugene F. Fama and Kenneth R. French, business professors at the University of Chicago, traced the performance of thousands of stocks over 50 years but found no link between relative volatility and long-term returns. The many investors who try to beat the market by buying widely swinging issues are misguided, they say.

The importance of "beta," the investment community's term for a stock's volatility relative to the market, has long been under challenge. But it is still closely watched by analysts, and business students are still taught that they can earn higher returns by buying stocks whose swings are wider than the market's.

"The fact is," Professor Fama said in a recent telephone interview, "beta as the sole variable explaining returns on stocks is dead."

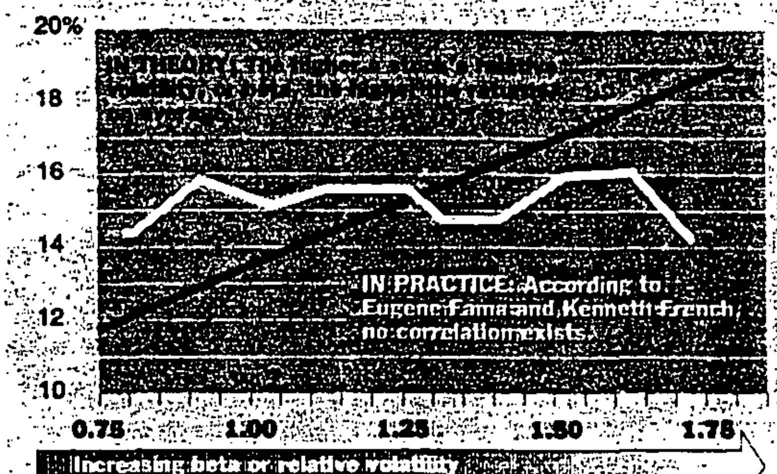
Some still favor relatively volatile stocks, among them William F. Sharpe, a retired Stanford University professor who won the 1990 Nobel Memorial Prize in Economic Science for theories based on beta. "It is a remarkable set of empirical results about what happened in the past," he said of the University of Chicago study. "But I am not willing to make investment decisions based on the theory that there is no relationship between beta, properly measured, and expected returns."

If Professors Fama and French

Continued on Page D6

Knocking Down a Popular Theory

Annual returns on stock investments, based on relative volatility.*



Beta measures the volatility of a stock relative to the market.

*Returns are based on average one-month Treasury bill yields, annualized, and average market returns; July, 1963 to December 1990.

Source: Eugene F. Fama and Kenneth R. French, University of Chicago

The New York Times

Market Place

A Study Shakes Confidence In the Volatile-Stock Theory

Continued From First Business Page

are right, however, the impact could be far reaching. Some highly volatile groups of stocks that have enjoyed wide followings — airlines, for example — could lose a portion of their appeal if beta-believing investors side with the professors.

Additionally, many executives of publicly held companies have taken the view that if their own company's stock is more volatile than the market as a whole, any project they invest in — from a lowly piece of new equipment to a huge joint venture — must generate an extra high return to compensate investors for swings in the stock's price and earnings. The professors' work could force many companies to rethink the way they approach capital spending, finance scholars say.

Finally, many publicly held utilities have used beta to justify rate requests. They figure the returns that investors demand, given their companies' betas, and develop rate structures that allow them to earn these returns. But recognizing that their low betas tend to argue against large rate increases, a growing number of utilities had already turned to other approaches. More will probably do so if the research of Professors Fama and French gains currency.

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And if investors decide to quit following betas, other theories of market behavior are likely to gain influence. "What we are really taking about is opening the floodgates to a whole new generation of research into what truly drives stock prices," said Anthony B. Sanders, an Ohio State University professor of finance who is currently a visiting professor at the University of Chicago. "Once you hammer a model like the old one closed, you generate all sorts of additional academic interest."

Professor Fama has already won worldwide recognition for his efficient-markets theory — the notion that because investors all have essentially the same information it is impossible to consistently earn returns greater than those justified by the risks.

• • •

Professor Sharpe used Professor Fama's theory as an assumption to develop the capital-asset pricing model, which links returns to risk, as measured by beta.

Professor Sharpe says that a diversified portfolio can reduce the risks peculiar to individual companies — that General Motors stock, for example, will be hurt by a strike. Investors, therefore, earn no rewards for bearing this risk, according to the Sharpe theory.

But investors do earn higher returns for bearing the other type of risk, known as market risk, Professor Sharpe says. This risk, which remains even after an investor diversifies, depends on how much an individual stock is dragged up or down by the market as a whole. Stocks like that of the biotechnology company Genentech, which have betas of more than 1.0, are more volatile than the market, while stocks like that of the power company Consolidated Edison, which have betas of less than 1.0, are calmer than the market.

To calculate market risk, or beta, finance professionals compare changes in the prices of individual stocks with changes in market indicators like the Standard & Poor's 500-stock index. Professor Sharpe and his followers say that in general, the higher a stock's beta, or volatility relative to the market, the greater its long-term returns.

• • •

Professors Fama and French disagree. Their paper, just published by the University of Chicago's Center for Research in Security Prices, says that long-term returns depend not on beta, but on company size and price-to-book ratios. Smaller companies, as measured by the market value of their shares, and those with low prices relative to their book values have in fact outperformed the market, they say.

The professors theorize that investors view smaller companies as more vulnerable to economic downturns and therefore demand higher returns. They also say that low price-to-book ratios typically reflect financial problems, another reason for investors to demand higher returns.

Professors Fama and French are by no means the first to fire an intellectual salvo at the capital-asset pricing model. Since Professor Sharpe developed the model in the early 1960's, a broad array of rival theories has emerged to explain stock price movements: the January effect, which says that stocks usually gain at the beginning of the year, to the weekend effect, which says stocks generally perform poorly on Mondays. Most recently, the arbitrage pricing theory says that stocks are driven by powerful economywide forces like unanticipated inflation and spikes in interest rates.

But finance experts say that Professors Fama and French have presented the most conclusive evidence against beta.

"What they have proven fairly rigorously is what other academics have been talking about for some time," said Richard Roll, a finance professor at the University of California at Los Angeles, who with others developed the arbitrage pricing theory.

Equity Issues This Week

OTS Exhibit No. 1
Schedule No. 8

Comparison of Debt to Total Capital and Percent Institutional Holdings
for Mr. Moul's Comparable Earnings Barometer Group
Compared to the Barometer Group of Eight Electric Companies
and the Pennsylvania Power & Light Company at March 1, 1995

	Company	(1) Debt to Total Capital (%)	(2) Institutional Holdings (%)
(1)	Allegheny Corporation	31.0	55.0
(2)	Ameron, Inc.	44.0	36.6
(3)	Amoco Corporation	23.0	59.1
(4)	Atlantic Richfield	54.0	59.5
(5)	Chevron Corporation	23.0	43.5
(6)	Cincinnati Financial	4.0	31.7
(7)	Commercial Metals	23.0	45.9
(8)	Exxon Corporation	20.0	40.0
(9)	Fab Industries	1.0	45.6
(10)	Flowers Industries	25.0	44.4
(11)	GEICO Corporation	21.0	77.8
(12)	Joslyn Corporation	.0	38.8
(13)	JSB Financial	.0	38.3
(14)	Lee Enterprises	29.0	69.1
(15)	Mobil Corporation	23.0	52.1
(16)	Murphy Oil Corporation	8.0	59.6
(17)	Nash Finch Company	31.0	35.2
(18)	Raytheon Company	1.0	71.5
(19)	Tennant Company	1.0	66.8
(20)	Texaco Company	37.0	55.7
(21)	Thomas & Betts	45.0	72.6
(22)	U.S. Trust	22.0	64.3
(23)	West Company	12.0	52.4
(24)	23 Company Average	20.8	52.8
(25)	Barometer Group Average	46.0	29.7
(26)	Pennsylvania Power & Light Company	49.0	21.0

Sources: Value Line-Value Screen Data Base, March 1, 1995

OTS Statement No. 5 & Exh 5
Dated: April 14, 1995
4/27/95
1:05
Jor

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

Direct Testimony

of

Paul J. Metro

Concerning:

Excess Capacity
Electric Plant Held For Future Use

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

A. My name is Paul J. Metro. My business address is P.O. Box 3265, Harrisburg, Pennsylvania, 17120.

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

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Valuation Engineer working in the Rate Structure/Engineering Section of the Energy Division.

Q. **WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I am a 1982 graduate of The Pennsylvania State University, University Park, Pennsylvania, where I earned a Bachelor of Science Degree in Mineral Economics. Immediately subsequent to graduation, I attended The Pennsylvania State University and met the requirements for a Bachelor of Science Degree in Industrial Engineering. I am also a graduate of The Pennsylvania State University with a Masters of Engineering Degree, majoring in Engineering Science with an emphasis on Industrial Engineering/Operations Research. I have been employed by the Pennsylvania Public Utility Commission since May of 1985. Attached to this testimony as Appendix A is a statement which more fully describes my educational background and employment experience.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to demonstrate that: (1) Pennsylvania Power & Light Company (PP&L) has 564 Mega-watts (MW) of excess generation capacity and (2) PP&L's proposal for Electric Plant Held For Future Use is not in the ratepayers best interest and should be disallowed.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have segmented my Direct Testimony into three sections. Section I contains the excess generating capacity discussion and exhibits. Section II evaluates the Company's proposal for Electric Plant Held For Future Use. Section III contains a summary of my recommendations and findings.

SECTION I. - EXCESS GENERATION

<u>Company Position</u>

Q. MR. METRO, WHAT DEMAND LEVELS WERE PROJECTED BY THE COMPANY FOR THE WINTER PEAK LOAD DURING THE 1995/1996 WINTER?

A. As can be seen in Exhibit JFS-1, the projected Winter Peak Load for the winter of 1995/1996 is 6,725 MW. I would note that the projected Winter Peak Load includes the demand of PP&L's full requirement resale customers (municipal customers and Citizens Electric Company) and PP&L's partial requirement customers (Electric Utility Division of UGI and Allegheny Electric Cooperative). <u>See</u> PP&L Stmt. No. 9, Page 5, Lines 21-23. In addition, as can be seen in Exhibit JFS-1, the projected Winter Peak Load increases by approximately 1.9% each year (except for the winter of 1996/1997) up to the year 2004.

Q. MR. METRO, WHAT ARE THE COMPANY'S PROJECTED TOTAL OWNED AND LEASED CAPACITY CLAIMED IN THIS FILING?

A. The Company's projected owned and leased capacity at September 30, 1995 is 8,540 MW (winter ratings). (<u>See</u> PP&L Stmt. No. 9, Page 5, Lines 21-23). The resources available at September 30, 1995 were adjusted by the Company for the derate of Martins Creek 3 & 4 (-13 & -35 MW) and are adjusted by the Company for the uprate of Susquehanna 1 of 45 MW. After September 30, 1995, the owned and leased capacity levels are projected by the Company to increase for the uprate of Martins Creek 3 & 4 (13 & 35 MW) in 1997 and decrease for the derate of Montour 1 (-18 MW) in 1999 and decrease for the derate of Montour 2 (-18 MW) in 2000. (See PP&L Stmt. No. 9, Page 5, Lines 21-23).

Q. ARE THE COMPANY'S TOTAL OWNED OR LEASED CAPACITY LEVELS REDUCED BY FIRM CAPACITY SALES TO OTHER UTILITIES?

A. Yes it is. PP&L has agreements to sell firm capacity and energy to Atlantic Electric, Baltimore Gas & Electric, and Jersey Central Power & Light. As can be seen in the Company's Exhibit JFS-1: (1) the Atlantic Electric Firm Capacity sale is for 129 Mw; (2) the Baltimore Gas & Electric Firm Capacity sale is for 132 MW; (3) the Jersey Central Power & Light Firm Capacity sale is for 945 MW. The Firm Capacity sales contracts to Atlantic Electric and Jersey Central Power & Light expire in the year 2000, while the Baltimore Gas & Electric contract expires in the year 2001. The JCP&L contract is phased-out over a period of five years beginning in 1996. This phaseout adds 189 MW to the Company's resources for each of the succeeding five years.

Q. AFTER THE FIRM CAPACITY SALES TO OTHER UTILITIES ARE SUBTRACTED FROM PP&L'S OWNED OR LEASED CAPACITY LEVELS, WHAT LEVEL OF RESOURCES REMAIN AT THE TIME OF PEAK?

A. As can be seen in Exhibit JFS-1, the net resources at the time of peak, excluding Firm Capacity Sales to Other Utilities is 7,334 MW for the winter of 1995/1996. The net resources at the time of peak are projected, by the Company, to increase over the next several years.

Q. MR. METRO, UP TO THIS POINT YOU HAVE DESCRIBED THE COMPANY'S CALCULATIONS FOR ITS BASIC CAPACITY LEVEL AND ITS BASIC DEMAND LEVEL. WHAT DOES PP&L'S COMPARISON OF CAPACITY AND DEMAND LEVELS SHOW?

A. As shown in the Company's Exhibit JFS-1, the reserves at the time of peak, for the winter of 1995/1996, without including NUG load and Interruptible customer resources, are 609 MW (9.1% greater than winter peak load). As seen in JFS-1, the reserves at the time of peak grow until the winter of 2001/2002, at which time a slight reduction in reserves at the time of peak are projected.

Q. **WHAT IS PP&L'S POSITION CONCERNING THE ADDITION OF INTERRUPTIBLE CUSTOMER RESOURCES TO THE RESERVES AT THE TIME OF PEAK?**

A. PP&L's Statement No. 9 -Direct Testimony of John F. Sipics, addresses PP&L's position concerning the inclusion of load created by the interruption of the Interruptible customers (Page 11, Lines 23-30 & Page 12, Lines 1-4). Basically, PP&L believes that the most appropriate reserve level for assessing PP&L's reserve margins are the reserves at the time of peak that include the load associated with Interruptible customers.

Q. **MR. METRO, WHAT IS THE COMPANY'S CLAIMED LOAD ASSOCIATED WITH INTERRUPTIBLE CUSTOMERS?**

A. The Company's projected value of PP&L's Interruptible load is 345 MW as can be seen in the Company's Exhibit JFS-1.

Q. WHAT IS THE COMPANY'S CLAIM FOR RESERVES AT THE TIME OF PEAK WITH INTERRUPTIBLE LOAD INCLUDED?

A. The Company's claim for Reserves at the Time of Peak with Interruptible load included, for the winter of 1995/1996, are 954 MW (609 MW + 345 MW) (See Company's Exhibit JFS-1). This level of reserve at the time of peak establishes a reserve margin, as a function of winter peak demand, of 14.2%. As seen in JFS-1, the reserves at the time of peak, with the Interruptible load included, grow until the winter of 2001/2002, at which time a slight reduction in reserves at the time of peak are projected.

Q. WHY DOES THE COMPANY BELIEVE THAT THE INTERRUPTIBLE LOAD SHOULD BE INCLUDED IN THE RESERVES AT THE TIME OF PEAK?

A. PP&L states that it exercised control over the addition of owned and leased generation and exercised partial control over the addition of interruptible load (Page 11, Lines 23-30 & Page 12, Lines 1-4).

Q. DOES PP&L SHOW, ON EXHIBIT JFS-1, NON-UTILITY GENERATION (NUG) AS A RESOURCE?

A. Yes, PP&L shows NUG generation as an installed capacity. However, PP&L is of the opinion that NUG generation should not be utilized in the calculation of Reserves at the Time of Peak. PP&L's opinion is primarily based on the fact that it did not exercise control over the addition of the non-utility generation and currently does not exercise control over the addition of NUGs. (Page 11, Lines 23-30 & Page 12, Lines 1-15).

Q. WHAT LEVEL OF NUG GENERATION DOES THE COMPANY SHOW IN EXHIBIT JFS-1?

A. PP&L shows 474 MW available from NUG generation in Exhibit JFS-1.

Q. WHAT DOES THE COMPANY'S EXHIBIT JFS-1 SHOW FOR RESERVES AT THE TIME OF PEAK WITH NUG AND INTERRUPTIBLE LOAD INCLUDED?

A. As seen in the Company's Exhibit JFS-1, the Reserves at the Time of Peak, with Interruptible load and NUG load included, are 1,428 MW for the winter 1995/1996. This level of reserve at the time of peak establishes a reserve margin, as a function of winter peak demand, of 21.2%. As seen in JFS-1, the reserves at the time of peak, with the Interruptible load and NUG load included, grow until the winter of 2001/2002, at which time a slight reduction in reserves at the time of peak are projected.

Q. MR. METRO, THE COMPANY'S EXHIBIT JFS-1 ALSO SHOWS A COLUMN TITLED "CAPACITY CREDIT SALES TO OTHER PJM UTILITIES". PLEASE EXPLAIN WHAT CAPACITY CREDIT SALES ARE?

A. As explained in PP&L's Stmt. No. 9, Page 4, Lines 24-30, an installed capacity credit is a transaction between an installed capacity-deficient PJM member utility and a PJM member utility that has sufficient capacity reserves. The installed capacity-deficient PJM member utility can purchase the right to claim a portion of the installed capacity of a PJM member utility that has sufficient capacity reserves in order to meet its capacity obligation under the PJM Agreement.

Q. IS THE SALE OF ENERGY INVOLVED IN A CAPACITY CREDIT TRANSACTION?

A. No sale of energy is involved. According to the terms of the these type transactions, the selling utility retains full use of all the units involved and the associated energy (PP&L's Stmt. No. 9, Page 4, Lines 24-30).

Q. HOW DO PJM ACCOUNTING PROCEDURES TREAT AN INSTALLED CAPACITY CREDIT SALES?

A. PP&L's capacity credit sales result in a reduction in the seller's resources and an increase in the purchaser's resources for installed capacity accounting purposes only.

Q. MR. METRO, THE TESTIMONY ABOVE DISCUSSED VARIOUS SCENARIOS OF PP&L'S FORECASTED LEVEL OF LOAD AND CAPACITY AND THE RESERVES THAT ARE AVAILABLE AT THE TIME OF PEAK. WHAT IS THE COMPANY'S POSITION CONCERNING RESERVES AT THE TIME OF PEAK IN RELATION TO PP&L'S OBLIGATION TO PROVIDE RELIABLE ELECTRIC SERVICE TO ITS CUSTOMERS?

A. PP&L'S Statement No. 9, Page 7 states:

> **"In order to assure reliable, reasonably continuous service to customers, an electric utility must have resources equal to its anticipated peak demands plus a reasonable reserve margin. A reserve margin must be maintained for a variety of reasons including, principally, the unavailability of generating capacity due to planned and unplanned outages and the potential that customers demand could exceed forecasted peaks."** (Lines 17-22)

Q. WHAT IS THE COMPANY'S POSITION CONCERNING THE LEVEL OF RESERVE MARGIN THAT IT BELIEVES IS APPROPRIATE TO SATISFY ITS OBLIGATION TO ITS ELECTRIC SERVICE CUSTOMERS?

A. PP&L considers an appropriate reserve margin to be within a range bound by a minimum reserve requirement of approximately 12 percent and a maximum reserve requirement of approximately 22 percent (PP&L Stmt. No. 9, Page 12, Lines 27-30 through Page 13, Lines 1-14).

Q. FOR PURPOSES OF THIS RATE PROCEEDING, ON WHAT BASIS DOES PP&L WANT ITS RESERVE MARGINS ASSESSED?

A. For purposes of this rate proceeding, PP&L believes that its reserve margins are most appropriately assessed on the basis of its: (1) owned and leased generation and (2) available Interruptible load (Stmt. No. 9, Page 13, Lines 9-12). As can be seen in the Company's Exhibit JFS-1, Reserves at the Time of Peak, with Interruptible load included, reflect reserve margins ranging from a low of 14.2 percent (1995/1996) to a high of 19.6 percent (2000/2001).

OTS Position

Q. **MR. METRO, WHAT ARE THE RESULTS OF YOUR ANALYSIS OF PP&L'S PROJECTED LOAD AND CAPACITY LEVELS?**

A. After reviewing the Company's Exhibit JFS-1 and associated responses to OTS Interrogatories, I have concluded that PP&L has 564 MW of excess capacity.

Q. **MR. METRO, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING PP&L'S CAPACITY LEVELS?**

A. I recommend that the Commission reduce PP&L's net Production Plant in Service associated with 564 MW of excess generating resources.

Discussion

Q. **MR. METRO, DO YOU AGREE WITH PP&L'S WINTER PEAK LOAD PROJECTIONS?**

A. Yes I do. PP&L's estimate of the winter peak load is reasonable.

Q. **DO YOU AGREE WITH PP&L'S ASSERTIONS THAT A RESERVE MARGIN SHOULD BE THOUGHT OF AS EXISTING WITHIN A RANGE?**

A. No I do not. In my opinion, PP&L'S reserve margin should be thought of as a single figure.

Q. WHY SHOULD PP&L'S RESERVE MARGIN BE THOUGHT OF AS A SINGLE FIGURE?

A. The purpose of a reserve margin is to supply customer demand under reasonable conditions equal to a loss of load criteria of no more than one event in ten years. The reserve margin under this scenario is a single figure.

Q. MR. METRO, WHAT IS YOUR RECOMMENDED RESERVE MARGIN?

A. In my opinion, the reserve margin should be equal to PP&L's allocated portion of PJM's overall reserve requirement, which is determined over a defined planning period, and expressed as a function of winter peak load, plus an additional forced outage factor. Based on this allocation, PP&L should have resources that provide approximately 16 (15.72%) percent reserve margin.

Q. **IN YOUR OPINION, IS THE 16 PERCENT RESERVE MARGIN A SUFFICIENT LEVEL OF RESERVE TO PROVIDE SAFE, REASONABLE, AND ADEQUATE SERVICE TO PP&L'S CUSTOMERS?**

A. PP&L obviously needs capacity over and above its projected peak load. What is in question is the amount that is necessary to provide safe, reasonable and adequate service to PP&L's customers. In my opinion, the 16 percent reserve margin is a sufficient level of reserve to provide safe, reasonable, and adequate service to PP&L's customers.

Q. **WHY IS THE 16 PERCENT RESERVE MARGIN A SUFFICIENT LEVEL OF RESERVE TO PROVIDE SAFE, REASONABLE, AND ADEQUATE SERVICE TO PP&L'S CUSTOMERS?**

A. First, looking at the winter of 1995/1996, the 12 percent reserve margin required by PJM establishes a reserve above the winter peak load of approximately 807 MW (12%* 6,725 MW). The 807 MW is 3.23 times greater than the 1994 experienced forced outages of 250 MW (See OTS Exhibit 5, Schedule 3). In addition, I am also including an additional 250+ MW relating to forced outages. This factor will be discussed later in the testimony.

Second, and most importantly, PP&L is a member of the PJM power pool. A major benefit for PP&L from belonging to the PJM power pool is that PP&L's peak occurs in the winter while PJM's other utilities are summer peaking. Therefore, PP&L should be able to utilize the PJM power pool to serve loads that are greater than the 16 percent reserve requirement.

Q. MR. METRO, DO YOU CONSIDER RESOURCES OVER AND ABOVE THE 16 PERCENT RESERVE MARGIN AS EXCESS GENERATING CAPACITY?

A. Yes I do.

Q. MR. METRO, WHAT IS YOUR DEFINITION OF EXCESS CAPACITY AS IT RELATES TO PP&L'S BASE RATE FILING?

A. I define excess capacity in terms of reliability. Excess capacity is a situation where a utility has capacity over and above that necessary to meet peak demand plus ensure that there is a margin to allow for day to day variations in the operating conditions of installed generation.

A second definition of excess capacity exists that defines excess capacity in terms of economics. However, I do not believe that the economic definition of excess capacity applies to PP&L since it normally relates to new facilities.

Q. WHAT GENERATING RESOURCES SHOULD BE INCLUDED IN DETERMINING WHETHER PP&L HAS EXCESS CAPACITY?

A. I recommend that the Commission assess PP&L's capacity levels by including (1) PP&L's owned and leased generation, (2) available Interruptible load, and (3) non-utility generators.

Q. WHAT GENERATING RESOURCES DOES PP&L BELIEVE SHOULD BE INCLUDED IN ITS CAPACITY CALCULATIONS?

A. As I discussed above, PP&L's believes that its reserve margins should be assessed without the inclusion of NUG generation. PP&L's avers that it did not have control over the addition of non-utility generation and that this generation was forced onto PP&L after its last capacity addition was substantially completed.

Q. WHY SHOULD NUG GENERATION BE INCLUDED IN PP&L'S CAPACITY CALCULATIONS?

A. First, NUG generation should be included in PP&L's capacity calculations because Federal Law requires electric utilities to purchase power from NUGs.

Second, NUG generation is as reliable as PP&L's own generation as shown in OTS Cross Examination Exhibit No. 3.

Third, there is an inherent risk with bringing large nuclear plants on line; whether PP&L had bad timing and luck with the development of Susquehanna 1 and 2 or whether PP&L had poor planning and vision toward the development of NUG generation, the result of PP&L's action and/or inaction lies solely with PP&L and its shareholders.

Fourth, NUG power is used by PP&L to meet its daily demand and therefore should be counted as a Resource at the time of peak.

Fifth, NUG power is recognized by PJM as a resource for installed capacity accounting purposes.

Q. UTILIZING THE THREE GENERATING RESOURCES, (1) PP&L'S OWNED AND LEASED GENERATION, (2) AVAILABLE INTERRUPTIBLE LOAD, AND (3) NON-UTILITY GENERATORS, WHAT RESERVES AT THE TIME OF PEAK ARE AVAILABLE TO PP&L?

A. As seen in the Company's Exhibit JFS-1, the Reserves at the Time of Peak, with Interruptible load and NUG load included, are 1,428 MW for the winter 1995/1996. This level of reserve at the time of peak establishes a reserve margin, as a function of winter peak demand, of 21.2%. As seen in JFS-1, the reserves at the time of peak, with the Interruptible load and NUG load included, grow until the winter of 2001/2002, at which time a slight reduction in reserves at the time of peak are projected. The range of reserve margins for the ten years shown in JFS-1 vary from a low of 21.0% to a high of 26.0%.

Q. MR. METRO, HOW DID YOU DERIVE YOUR EXCESS CAPACITY ADJUSTMENT?

A. Please refer to OTS Exhibit 5, Schedule 1. As can be seen in Schedule 1, I basically duplicated the Company's Exhibit JFS-1, with some minor modifications. Schedule 1 shows the net resources at the time of peak including NUG and interruptible load for the nine years beginning with the winter of 1995/1996.

Q. PLEASE EXPLAIN THE MINOR ADJUSTMENTS THAT ARE SHOWN ON OTS EXHIBIT 5, SCHEDULE 1.

A. There are two minor modifications shown on Schedule 1 that do not appear on the Company's Exhibit JFS-1. First, I included an additional factor for Forced Outages. Second, I depicted, on Schedule 1, the 12 percent PJM requirement associated with the winter peak load.

Q. MR. METRO, WOULD YOU PLEASE EXPLAIN THE FORCED OUTAGE FACTOR?

A. Yes I will. Included within PP&L's 12 percent reserve requirement is a level of forced outages (See Tr. Page 327, Lines 9-23). I have included in Schedule 1 an additional Forced Outage of 250 MW - 290 MW over and above the forced outage amount included within the 12 percent reserve requirement. The effect of including an additional Forced Outage factor is to reduce the total available resources. I calculated the forced outage factor by using the 1994 experienced forced outages and then trending that amount upwards in relationship to an increase in the net resources at the time of peak (See OTS Exhibit 5, Schedule 3).

Q. WHY DID YOU INCLUDE A FORCED OUTAGE FACTOR IN SCHEDULE 1?

A. I included an additional Forced Outage factor in Schedule 1 to recognize the fact that forced outages can occur during peak periods.

Q. WHAT IS YOUR SECOND MODIFICATION SHOWN IN SCHEDULE 1?

A. The second modification reflects the winter peak load as a function of the PJM 12 percent reserve requirement. This modification was shown in order to calculate an excess available resources over and above the 12 percent reserve requirement.

Q. MR. METRO, EXPLAIN HOW THE EXCESS AVAILABLE RESOURCES WERE CALCULATED IN OTS EXHIBIT 5, SCHEDULE 1?

A. First, as can be seen in Schedule 1, for the year 1995/1996, I added the net resources at the time of peak with the resources available from the Interruptible load plus the resources available from NUG generation. This summation equals the total available resources at the time of peak.

Second, I then subtracted the Forced Outage factor that I described above. The amount remaining represents the net available resources at the time of the winter peak load.

Third, the next line shows PP&L's projected winter peak load. I then multiplied the projected winter peak load by the PJM 12 percent reserve requirement. This level of load represents the amount of generation that is needed to meet the 12 percent reserve requirement.

Fourth, Schedule 1 shows the yearly excess capacity levels as a function of the 12 percent reserve margin. For example, for the year 1995/1996, the net available resources minus the PJM 12 percent requirement equals an excess available resource of 371 MW.

Finally, the nine year excess available resources were averaged to derive a nine year average excess available resources.

Q. WHAT EXCESS GENERATION LEVEL DOES SCHEDULE 1 SHOW?

A. OTS Exhibit 5, Schedule 1 shows an average excess generation level of 564 MW.

Q. WHY ARE YOU USING A NINE YEAR AVERAGE TO REPRESENT THE EXCESS GENERATION ADJUSTMENT?

A. In my opinion, the nine year average is a reasonable representation of a level of excess generation that PP&L will incur given the Company's projected demand levels and total available resources. In addition, the nine year average will permit PP&L to plan for future firm capacity sales to other utilities and plan for future generating capacity additions.

Q. **MR. METRO, IF YOU DID NOT INCLUDE THE ADDITIONAL FORCED OUTAGE FACTOR, WOULD YOUR EXCESS GENERATION ADJUSTMENT BE HIGHER?**

A. Yes it would. If I removed the additional forced outage factor, the excess generation adjustment would be at a level of 840 MW. The Forced Outage factor basically reduces PP&L's reserves at the time of peak. The reduced reserves equate to a minimum reduction of 250 MW.

Q. **MR. METRO, FOR THE WINTER PERIOD OF 1995/1996 WOULD YOU PLEASE QUANTIFY THE RESERVES THAT PP&L WILL ENJOY OVER AND ABOVE ITS WINTER PEAK PROJECTED LOAD WITH YOUR EXCESS CAPACITY ADJUSTMENT INCLUDED?**

A. Yes I will. As can be seen in OTS Exhibit 5, Schedule 1, the difference between the winter peak load and the PJM requirement of 12 percent is 807 MW (7,532 MW - 6,725 MW). If one also considers the additional

250 MW of Forced Outages that are included in the net available resources, the total reserve over and above the winter peak load that PP&L will enjoy is 1,057 MW (250 MW + 807 MW).

Another way of determining the available reserves at the time of peak is to refer to the Company's Exhibit JFS-1. As can be seen in Exhibit JFS-1, the Company has 1,428 MW of reserves at the time of peak for the period of 1995/1996 (Company owned capacity plus Interruptible load plus NUG generation). If one reduces the 1,428 MW by the 371 excess adjustment for that year (OTS Exhibit 5, Schedule 1), the reserve at the time of peak is 1,057 MW (1,428 MW - 371 MW).

Q. WHAT IS THE RATE BASE EFFECT OF YOUR 564 MW EXCESS CAPACITY ADJUSTMENT?

A. OTS Exhibit No. 5, Schedule 2 depicts the rate base effect associated with the 564 MW excess capacity adjustment. As can be seen in Schedule 2, net production plant for the Pennsylvania jurisdiction should be decreased by $239,474,000.

Q. MR. METRO, WHAT IS THE REVENUE EFFECT OF YOUR RATE BASE ADJUSTMENT?

A. The revenue effect associated with my rate base adjustment is approximately $33 million. See OTS Exhibit 4, Schedule 15, sponsored by OTS witness Mr. Weakley.

Q. DOES YOUR EXCESS CAPACITY ADJUSTMENT INCLUDE THE INCREMENTAL RETURN OF CAPACITY ASSOCIATED WITH THE FIVE YEAR PHASE-OUT OF THE JCP&L AGREEMENT?

A. Yes it does. On January 1, 1996, the JCP&L agreement begins to phase-out over a five year period. Beginning January 1, 1996 and each year thereafter, the 945 MW slice will be reduced by 189 MW until the agreement terminates at the end of the year 2000. (See PP&L's Stmt. No. 7, Page 22). The phase-out will increase PP&L's resources by 189 MW in each of the succeeding five years.

Q. WHAT IS PP&L'S PROPOSAL CONCERNING THE CALCULATION OF ITS ENERGY COST RATE (ECR) AND THE TERMINATION OF THE JCP&L AGREEMENT?

A. PP&L is proposing that the calculation of its ECR be modified to permit the recovery of the Pennsylvania jurisdictional portion of the non-energy revenue requirements associated with bulk power capacity and energy agreements which have terminated, in whole or in part, and have not been replaced with new agreements and/or otherwise reflected in the calculation of the Company's base rate charges. (See PP&L's Stmt. No. 7, Page 21, Lines 11-20).

Q. EXPLAIN WHAT THE PENNSYLVANIA JURISDICTIONAL PORTION OF THE NON-ENERGY REVENUE REQUIREMENTS REFER TO.

A. An example of the Pennsylvania jurisdictional non-energy revenue requirements would be the returning rate base and expenses associated with capacity and energy from the phase-out of the Jersey Central Power & Light Firm Capacity (JCP&L) sale of 945 MW. Presently, the non-energy revenue requirements are excluded from PUC jurisdictional customer's base rates. This was accomplished by allocating cost assignments of the applicable rate base and operating expenses to PP&L's non-jurisdictional operations. (See PP&L's Stmt. No. 7, Pages 21 & 22, Lines 17-20 & 1-3).

Q. EXPLAIN WHY RATE BASE AND OPERATING EXPENSES WERE ALLOCATED AWAY FROM THE PENNSYLVANIA JURISDICTIONAL CUSTOMERS?

A. PP&L entered into a long-term capacity and energy agreement to sell a 945 MW slice of its system to JCP&L. This agreement was entered into subsequent to the Commission's Order that dealt with the Susquehanna Unit No. 1 being placed into service. In developing the revenue requirement claim in the Susquehanna Unit No. 2 base rate filing at Docket No. R-842651, PP&L completely excluded the costs of the 945 MW slice of its system sold to JCP&L. (See PP&L's Stmt. No. 7, Page 22, Lines 5-12).

Q. HAS PP&L EXCLUDED THE REVENUE REQUIREMENT ASSOCIATED WITH THE JCP&L AGREEMENT IN THIS BASE RATE FILING?

A. In this proceeding, PP&L has excluded all revenue requirements associated with the JCP&L agreement.

Q. HOW WILL PP&L USE THE ENERGY ASSOCIATED WITH EACH 189 MW INCREMENT RETURNED TO PP&L FROM JCP&L?

A. PP&L avers that the associated energy would be used to either serve the Company's native load customers or to make off-system energy sales. (See PP&L's Stmt. No. 7, Page 23, Lines 7-12).

Q. HOW DOES PP&L PROPOSE TO ACCOUNT FOR THE REVENUES IT MAY RECEIVE FROM OFF-SYSTEM ENERGY SALES ASSOCIATED WITH THE 189 MW INCREMENTS?

A. If its proposal is accepted by the Commission, PP&L proposes to credit its ECR with 100% of the PUC jurisdictional portion of capacity related off-system revenues received from PJM installed capacity credit, out-put reservation and transmission entitlement sales, net of associated PJM installed capacity credit, out-put reservation and transmission entitlement purchases. (See PP&L's Stmt. No. 7, Page 23, Lines 13-18).

Q. DO YOU OPPOSE THE COMPANY'S ECR PROPOSAL?

A. No, I do not. The net capacity resources used to calculate my excess capacity adjustment include the addition of 189 MW of capacity in each of the five years 1996 through 2000 as the JCP&L agreement is phased out.

Q. MR. METRO, WOULD YOU PLEASE SUMMARIZE THIS SECTION?

A. I recommend that the Commission reduce PP&L's claimed rate base by $239,474,000 associated with the net production plant in service related to 564 MW of excess capacity. The excess capacity adjustment is a slice of the system adjustment.

SECTION II. - PLANT HELD FOR FUTURE USE

Q. MR. METRO, WHAT IS THE COMPANY'S REQUEST CONCERNING ELECTRIC PLANT HELD FOR FUTURE USE?

A. PP&L is requesting the Commission to approve the accruing of a return component equivalent to the applicable Allowance For Funds Used During Construction (AFUDC) rate on future use property investments. PP&L proposes to include all accrued amounts as part of Electric Plant in Service at the time the plant is placed into service. PP&L is not making a request in this proceeding to include Electric Plant Held For Future Use in its future test year rate base claim. (See PP&L's Stmt. No. 7, Pages 27 & 28)

Q. WHAT IS YOUR POSITION CONCERNING PP&L'S PROPOSAL?

A. I recommend that the Commission deny PP&L's request to begin accruing a return component equivalent to the applicable AFUDC rate on its future use property investments. I also recommend that the Commission deny PP&L's request to include all accrued amounts as part of the Electric Plant In Service at the time such plant is placed into service.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATIONS?

A. I have been advised by counsel that the basis for my recommendation is a legal argument based on interpretations of court costs. Accordingly, the legal argument will be presented in OTS' Main Brief. However, I may add that the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts permits the accrual of AFUDC on electric plant held for future use (including land) only for the period of construction.

Q. MR. METRO, DO YOU HAVE AN ALTERNATIVE POSITION CONCERNING PP&L'S PROPOSAL RELATING TO ELECTRIC PLANT HELD FOR FUTURE USE?

A. Yes I do. I recommend that if the Commission grants PP&L's proposal, that such allowance be only for accounting purposes. Prudency determination of the plant held for future use would occur during a future rate case when the electric plant value is claimed in rate base.

SECTION III. - SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. MR. METRO, WOULD YOU PLEASE PROVIDE A BRIEF SYNOPSIS OF YOUR FINDINGS AND RECOMMENDATIONS?

A. Yes, I will briefly discuss each of the Sections that I delineated above.

In Section I, of my direct testimony, I recommend that the Commission reduce the net production plant in service associated with an excess capacity adjustment by $239,474,000. In Section II, of my direct testimony, I recommend that PP&L's proposal to begin accruing a return component equivalent to the applicable AFUDC rate on its Electric Plant Held for Future Use be denied and/or modified.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A

Professional and Educational Experience
of
Paul J. Metro

Education

The Pennsylvania State University, University Park, Bachelor of Science, Mineral Economics, 1982

Earned additional credits in Industrial Engineering from 1982-1984, The Pennsylvania State University, University Park

The Pennsylvania State University, Capitol Campus, Master of Engineering Science, Industrial Engineering/Operations Research Emphasis, 1992.

Professional Experience

March 1994 to Present: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Rate Structure/Engineering Section, Energy Division, Office of Trial Staff. Participates in the review and prosecution of natural gas and electric rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

December 1987 to March 1994: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Engineering Section, Engineering and Rate Design Division, Office of Trial Staff. Participates in the review and prosecution of gas, electric, telecommunications, water, and sewer rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

September 1986 to December 1987: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Engineering Section, Rate Design Division, Office of Trial Staff. Participated in the review and prosecution of gas, electric, telecommunications, and water rate filings in the areas of cost of service and tariff rules and regulations.

May 1985 to September 1986: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Valuation Section, Gas Division, Bureau of Rates. Participated in the review and prosecution of gas rate filings in the areas of valuation, depreciation, rate structure, purchased gas, and cost of service.

Professional Affiliations

Engineers Society of Pennsylvania

Testimony Presented Before The Pennsylvania Public Utility Commission

Equitable Gas Company, Transportation Investigation, R-870666,

UGI Corporation - Gas Division, Transportation Investigation, R-870665

National Fuel Gas Distribution Corporation, General Rate Case, R-870719

Equitable Gas Company, 1307(f) Proceeding, R-880932

Pennsylvania Gas & Water Company, 1307(f) Proceeding, R-880958

Equitable Gas - Energy Company, General Rate Case, R-880941

Equitable Gas Company, General Rate Case, R-880971

Equitable Gas Company, 1307(f) Proceeding, R-891238

Lake Latonka Water Company, General Rate Case, R-891257

Philadelphia Electric Company, General Rate Case, R-891364

Equitable Gas Company, 1307(f) Proceeding, R-901645

Roaring Creek Water Company, General Rate Case, R-901625

Equitable Gas Company, General Rate Case, R-901595

West Penn Power Company, General Rate Case, R-901609

Pennsylvania Gas & Water Company, 1307(f) Proceeding, R-901699

Western Utilities, Inc., General Rate Case, A-210017

T.W. Phillips Gas & Oil Co., 1307(f) Proceeding, R-911889

Columbia Gas of Pennsylvania, Inc., General Rate Case, R-901873

Columbia Gas of Pennsylvania, Inc., 1307(f) Proceeding, R-911921

Pennsylvania Gas & Water Company, 1307(f) Remand Proceeding, R-901699

Olwen Heights Water Company, General Rate Case, R-891226

Peoples Natural Gas Company, General Rate Case, R-922180

Pennsylvania Gas & Water Company, Transportation Tariff Filing, R-922169

Pennsylvania Gas & Water Company, 1307(f) Filing, R-922324

West Penn Power, General Rate Case, R-922378

Peoples Natural Gas Company, 1307(f) Filing, R-932598

Equitable Gas Company, 1307(f) Filing, R-932599

National Fuel Gas Distribution Company, General Rate Case, R-932548

Pennsylvania Gas & Water Company, Transportation Tariff Filing, R-932655

Allied Gas Company ET AL, Transportation Tariff Filing, R-932662

Peoples Natural Gas Company, General Rate Case, R-932866, R-932915

Peoples Natural Gas Company, 1307(f) Filing, R-943028

Columbia Gas of Pennsylvania, 1307(f) Filing, R-943029

Equitable Gas Company, 1307(f) Filing, R-943022

Pennsylvania Gas & Water Company, Tariff Filing, R-943078

OTS Exhibit No. 5
Dated: April 14, 1995

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

Exhibit to Accompany

the

Direct Testimony

of

Paul J. Metro

Concerning:

Excess Capacity
Electric Plant Held For Future Use

OTS EXHIBIT NO.5
SCHEDULE 1
WITNESS: PJ METRO

Excess Capacity Calculations	(With Forced Outages excluded from resources)								
	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
	MW	MW	MW	MW	MW	MW	MW	MW	MW
Net Resrces @ Peak Time	7,334	7,523	7,760	7,954	8,120	8,420	8,552	8,552	8,552
Plus: Interruptible Load	345	345	345	345	345	345	345	345	345
Plus: NUG	474	474	474	474	474	474	474	474	474
Total Available Resources	8,153	8,342	8,579	8,773	8,939	9,239	9,371	9,371	9,371
Minus: Forced Outages	250	256	264	271	277	287	291	291	291
Net Available Resources	7,903	8,086	8,315	8,502	8,662	8,952	9,080	9,080	9,080
Winter Peak Load	6,725	6,790	6,915	7,050	7,185	7,330	7,465	7,600	7,745
PJM Requirement (1.12%)	7532	7605	7745	7896	8047	8210	8361	8512	8674
Excess Available Resources	371	481	570	606	615	743	719	568	405
								9 Year Average	***564***

Reserves at the Time of Peak (MW)	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Plus: Interruptible Load	14.19%	15.88%	17.21%	17.72%	17.81%	19.58%	19.18%	17.07%	14.87%
Plus: NUG	21.23%	22.86%	24.06%	24.44%	24.41%	26.04%	25.53%	23.30%	20.99%
Minus: Forced Outages	17.52%	19.08%	20.24%	20.60%	20.56%	22.13%	21.63%	19.47%	17.23%

Source Company Exhibit JFS-1

Pennsylvania Power & Light Company
Adjustment for Excess Capacity
Future Test Year Ending September 30, 1995
($000)

	PP&L's Claim for Total Production Plant	OTS Adjustment for Excess Capacity
Production Plant - PA. Jurisdiction		
(1) Electric Plant in Service	$5,021,440	($331,755)
(2) Depreciation Reserve	($1,396,759)	$92,281
(3) Net Production Plant	$3,624,681	($239,474)

Calculation Steps

Step 1

$$\frac{564 \text{ MW}}{(4)\ 8{,}540 \text{ MW}} \times \$5{,}021{,}440 \qquad \$331{,}755$$

Step 2

$$\frac{564 \text{ MW}}{8{,}540 \text{ MW}} \times (\$1{,}396{,}759) \qquad (\$92{,}281)$$

Step 3

$$\frac{564 \text{ MW}}{8{,}540 \text{ MW}} \times \$3{,}624{,}681 \qquad \$239{,}474$$

Source: (1)(2)(3) - Company Exhibit JMK2, pages 55 - 58.
(4) - Company Attachment I-B-2

OTS Exhibit No. 5
Schedule 3
Witness: PJ Metro

OTS Forced Outage Factor

Year	1994
Lost Generation From Forced Outages (MWH)	2,188,960
Number of Hours/Year	8,760
Lost Generation From Forced Outages (MW)	250

Source: Company's response to OTS-RB-69