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E. Holbert

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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| APPLICATION OF PECO ENERGY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE | : : : : | Docket No. R-00973953 |

DIRECT TESTIMONY

OF

RICHARD LA CAPRA



On Behalf of:

OFFICE OF CONSUMER ADVOCATE



JUNE 1997

**TESTIMONY OF RICHARD LA CAPRA**

**FOR PENNSYLVANIA OFFICE OF THE CONSUMER ADVOCATE**

Q. MR. LA CAPRA, PLEASE IDENTIFY YOURSELF FOR THE RECORD AND SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

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

My experience has encompassed financial, ratemaking, load research, and generation supply planning issues. Over the last 26 years, I have worked on behalf of more than 50 clients in 26 states, and in several different countries, on issues involving utility and energy markets. Although my primary interest has been in the area of electric and gas utility regulation, I have also testified on telecommunications, water resources, and the regulated taxicab industry. I have contributed to seminal research in ratemaking and load research, and my clients have relied upon me for technical analysis, strategic guidance, and difficult negotiation assistance. Of particular relevance to this proceeding is my knowledge of electric industry restructuring concepts and proposals, competitive market pricing in a restructured generation market, and utility finance and ratemaking. I have assisted several New England utilities negotiate short- and long-term power purchase contracts with large wholesale electric companies such as New England Power Company and Northeast Utilities. I have testified as an expert witness on numerous occasions before public utility commissions including the New Hampshire

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

Q. PLEASE DESCRIBE THE SECTIONS OF YOUR TESTIMONY.

A. The first subject which I will address will be general criteria for recovery of stranded costs. Second I will discuss the methodology that allows us to estimate stranded costs. The third subject is the very important topic of mitigation of stranded costs. The fourth section of my testimony addresses regulatory assets, primarily deferred fuel and fossil unit decommissioning. The next section contains my recommendations for the sharing of stranded costs. Finally, I propose the specific stranded cost amounts that should be allowed into the CTC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying as to the appropriate computation of stranded costs and how stranded costs should be shared between investors and ratepayers. My stranded cost computation relies on the market price estimates produced by Mr. Douglas Smith.

Q. WHAT GENERAL CRITERIA SHOULD BE SATISFIED IN DETERMINING STRANDED COST TO BE RESPONSIVE TO THE ACT AND TO BE IN THE PUBLIC INTEREST?

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

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

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

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

Q. WOULD YOU PLEASE DISCUSS THESE CRITERIA IN MORE DETAIL?

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

It is also essential that the assets to be recovered would have been reasonably recoverable under traditional regulation. In addition, these costs, under the statute, must be known and measurable, presented on a net present value basis, and fit within the definition of stranded cost provided by the statue. The statutory definition sets forth three general categories of stranded cost recovery. The first category consists of regulatory assets, deferred charges, unfunded portions of projected nuclear decommissioning costs, and cost obligations with non-utility generating projects that have received a Commission order. For this category of costs, recovery is pursuant to Section 2808(c)(l) which provides that the Commission shall allow recovery of such costs once it is determined that they have met the requirements of the definition.

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

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

I. STRANDED COST METHODOLOGY

Q. WHAT ARE THE BASIC COMPONENTS OF STRANDED COSTS?

A. The Company has included stranded costs in each of the three categories identified in the Act, these are as follows:

1) Utility-owned generation-related costs;

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

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

In its filing, the Company has grouped its costs into somewhat different categories. My testimony reviews the Company's stranded costs in each of the three categories listed above, although my determinations about regulatory assets rely for the most part on Mr. Catlin.

Q. WHAT METHODOLOGY OF CALCULATING STRANDED COST ASSOCIATED WITH UTILITY-OWNED GENERATING ASSETS ARE YOU SUPPORTING?

A. The method utilized follows that utilized by PECO to a substantial degree. The basic approach to calculating the stranded cost associated with a generating asset requires calculating the difference between the value of the assets on the Company's books and an estimate of what a willing buyer would pay for the assets. The value to the willing buyer would be the net margins that would be received from these generating assets, plus any other value that might be created by these assets. The margin, in turn, is a function both of the revenues that would be earned in the competitive marketplace and the ongoing costs that must be incurred in order to operate the units. Potential buyers may also anticipate benefits from the ownership of the unit that are not financially reflected in the margin revenue analysis. We discuss this issue below under mitigation and under sharing.

Q. PLEASE DESCRIBE THE FIRST STEPS IN THE ESTIMATION OF THE MARKET VALUE OF GENERATING PLANT.

A. The first step is that of identifying the net book value of the assets less identified mitigation. Our computation differs from the Company only because of the Bureau of Audits adjustments and a site value adjustment, described later. The next step, that of computing the net margins earned by generating plant, essentially follows the path taken by the Company. A dispatch model estimates both the amount of generation that will be produced by each of the Company's generating units and also the market price of energy in each year of the analysis. To the energy revenues are added the capacity revenues for each unit to produce the market revenues. The energy prices are specific to each unit, reflecting the different hours in which they are producing energy. The going-forward costs of operating each unit are subtracted from the market revenue in each year to produce annual net margins.

Q. HOW IS YOUR COMPUTATION DIFFERENT FROM THAT OF THE COMPANY?

A. First, we have used a more realistic set of market prices, those developed in the testimony of Douglas Smith. Second, I have assumed that the Company will have some ability to further mitigate its going-forward costs by containing some of its on-going expenses. Specifically, I subtract an O&M expense from the generation market revenue which escalates at a lower rate than the Company's escalation. The going-forward costs also include the full amount of nuclear decommissioning, as recommended by Mr. Catlin. Finally, we determine net present value by discounting with the more relevant discount rate as approved by the Commission in PECO's QRO proceeding, and assuming a "mid-year" convention for the timing of revenues and expenses. These computations are discussed further in Section V.

Q. DOES THE COMPANY HAVE ANY STRANDED COSTS ASSOCIATED WITH PURCHASED POWER CONTRACTS?

A. The Company has testified that is does not have any stranded costs as a result of purchased power contracts. Most of its contracts have pricing terms that are tied to a PJM avoided cost. Since the current PJM avoided cost does not appear to have any capacity component, purchased power contracts may actually be below the market cost in the future, in which case they will be an offset to stranded costs.

Q. HAVE YOU MADE AN ADJUSTMENT TO STRANDED COST TO REFLECT PURCHASED POWER?

A. No, it appears that any such adjustment would be small. The primary reason that we have not made any adjustment however is that we have been unable to determine the exact price component in each of the contracts or how they may be interpreted in the future PJM rules.

## II. MITIGATION OF STRANDED COSTS

Q. THE ACT DESCRIBES THE COMPANY'S OBLIGATION TO MITIGATE STRANDED COSTS. HOW SHOULD THE COMPANY MITIGATE ITS STRANDED COSTS?

A. The Company can meet its mitigation obligation in two ways: first, by reducing the costs of continued operation of producing assets; and second, by reflecting all future value of current assets which have been funded by the PECO customers. The reduction of costs to enhance net revenues requires the Company to assess several areas of cost reduction, specifically a reduction of production operating expense, maximum possible improvement in the performance of generating units, a maximum feasible attempt to reduce purchased power costs from both utility and non-utility suppliers, and a plan to retire or sell units which do not have a net positive cash flow under reasonable market assumptions. The second area of mitigation, that of reflecting full value of assets, is where the Company's case is most deficient.

Q. THE COMPANY HAS ARGUED THAT IT HAS MET ITS MITIGATION OBLIGATION BY ACCELERATING DEPRECIATION. DO YOU AGREE?

A. While the Company's recent acceleration of depreciation reduced its stranded cost claim somewhat, this action does not satisfy the mitigation standard for two reasons. First, it did not involve an increase in efficiency or productivity on the part of the Company, and second it did not create value that was not otherwise provided by regulatory or governmental action. Customers will pay less in the future under this plan of accelerating depreciation but at the cost of a higher total revenue requirement than would otherwise be applicable in the near term.

Q. HAS THE COMPANY'S CASE REFLECTED THE MITIGATING EFFECTS OF FUTURE EXPENSE REDUCTIONS AND IMPROVEMENTS IN EFFICIENCY?

A. No. The Company has presented the interesting argument that they have made major strides in improving unit performance and in reducing expenses, but that there is no possibility of making any further improvements or reductions. I find this a very unlikely result. I will discuss our specific assumptions regarding cost reductions later in this section.

Q. WHY DID YOU STATE THE COMPANY'S CASE IS MOST DEFICIENT WITH REGARD TO REFLECTING THE FULL VALUE OF GENERATING ASSETS?

A. Mitigation should reflect all other sources of value which may be recoverable from the ownership of generating resources. If other buyers of generating assets find value in these assets in addition to the net margin estimated by ourselves or by the Company, they would pay more than the net margin; the market value will be higher than the net margin. Reflecting the full market value is clearly a basic part of such mitigation.

Q. WHY ARE THESE OTHER SOURCES OF VALUE IMPORTANT?

A. These sources of value are important, because the Company is not divesting itself of these assets. Under the restructuring plan certain rights and obligations will undergo a fundamental change. Among the more significant of these is the change in effective ownership of assets and the risks of operation. Under traditional regulation, a gain on a depreciable asset was considered for ratemaking as a cost item, i.e., if a utility sold an asset at a cost above its net book value, the gain after taxes was recognized as a reduction to its electric revenue requirements either in the current year or over some reasonable amortization period.

After the industry restructuring is completed there is a fundamental shift in this dynamic. The utility is the "owner" of each asset and is the beneficiary of a subsequent gain. Thus, the residual value of each asset, exclusive of those under traditional regulation, is no longer inconsequential. If this value is ignored, ratepayers will pay the full net book value of the generating assets, at the end of which the Company may then sell the sites and retain the sale proceeds.

The valuation of any asset is the sum of its net earning ability and its residual value. The Company has needed no encouragement to put forth estimates of negative residual value and on-going liability with, for example, its nuclear units. Many hydro and fossil units, on the other hand, will have significant value well past their book life.

Q. COULD YOU PROVIDE AN EXAMPLE WHICH INDICATES WHY THERE MAY BE MORE VALUE IN THE GENERATION ASSETS THAN THE NET MARGIN TO BE EARNED FROM THEM?

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

Q. HAVE YOU ESTIMATED THE POSSIBLE VALUE OF GENERATING SITES?

A. I have developed a "barebones" type of estimate. While it is difficult to determine an exact value for mitigation, it is clear that some mitigation is possible. I have estimated the current value of the bare land, although this will significantly understate value. I simply determined the number of years since the unit was constructed, assumed that this was the year the land was acquired, and escalated the book value by 4% annually to 1999. The increment from the actual book value is $25 million. Since land has generally escalated at much higher rates, this estimate is very conservative. The Company has correctly excluded the actual book value from its stranded cost computations.

Q. HAVE YOU ALSO ESTIMATED THE COST REDUCTION TYPE OF MITIGATION WHICH YOU DESCRIBED EARLIER?

A. Yes. I have estimated lower O&M expenditures.

Q. PLEASE DESCRIBE YOUR ASSUMPTIONS REGARDING FUTURE O&M EXPENSES.

A. PECO's 1997 O&M estimates seem reasonable. They have been estimated for individual generating units, for the nuclear units on the basis of current budget. However, the subsequent assumption that these unit specific O&M budgets must then increase at the rate of inflation assumes that the Company is unable to find any further efficiencies. We have included in "going-forward" costs the same concept that is now often used in incentive ratemaking, i.e., the increase in O&M expenses will be at rate of inflation less a productivity factor, which we have set at 0.2%.

Q. WHAT ASSUMPTIONS HAVE YOU MADE REGARDING PROPERTY TAXES?

A. With regard to property taxes, the Company has assumed that the current level continues through the life of the units. This is a reasonable assumption and we have not modified it.

Q. ARE THERE OTHER ELEMENTS OF COST REDUCTION RELATED TO THE CREATION OF NEW STRUCTURE IN WHICH THE COMPANY WILL RECOVER COSTS THROUGH A CTC?

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

A final item in mitigation of the Company's proposed stranded costs is the value of the enterprise retained by PECO. Traditionally, the customer received benefits from this on-going value of the utility company to the extent that it produced value or secured cost reductions. Post restructuring, the Company is left with a going concern value of significant proportions. This value has been created by its long term monopoly standing and funded by its customers. It now has the ability and means to market this value, again with no compensation to its customers. It is obvious, if not completely quantifiable, the great value inherent in PECO's name, its customer base, its ability to maintain significant market share within its traditional territory as well as in other areas and its corporate infrastructure. Any competing entry into this Pennsylvania utility market must be prepared to incur tremendous expenses to secure a market position. We note also that this market position will enable the going concern to expand into a variety of other energy-related and entirely distinct ventures. The value of these opportunities is continually recognized in the marketplace by increases in stock value when T&D systems are spun off or when the riskier generation business is financially secured through governmental or regulatory action. This key market position of PECO has resulted from its monopoly and now PECO is requesting its transfer to stockholders free of cost. This is unacceptable, particularly in the light of PECO's request for billions of dollars of stranded cost recovery guarantees. The Bureau of Audits Report of 5/22/97 noted that the Company has made significant investments in these unregulated enterprises.

Q. PLEASE SUMMARIZE YOUR VIEW OF MITIGATION.

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

III. Regulatory assets

Q. WHAT DO YOU BELIEVE SHOULD BE INCLUDED IN STRÂNDED COSTS OF THE COMPANY'S CLAIMED REGULATORY ASSETS?

A. Mr. Catlin has testified as to the correct values for regulatory assets. I have used his calculations for regulatory assets, except for deferred fuel and fossil fuel decommissioning, discussed below. Also, we have added a return on Mr. Catlin's FAS 109 numbers, which we believe is consistent with his approach.

Q. WHAT ARE THE DEFERRED FUEL COSTS THAT ARE IN DISPUTE?

A. The Company has requested as stranded cost collection a "regulatory asset" that includes an actual under collection of fuel costs, a Nuclear Performance award, and future deferred fuel. The projected "deferred fuel" issue was created when the Company rolled-in to base rates less than their average fuel costs over the 2/93 to 12/96 period. This was described by the Company as creating an undercollection of $22 million per year. Mr. Cohn's description of this element stated it reflected "the amount by which the Company's average energy costs rolled into base rates from its ECA understated its projected energy costs for the 9-year period from January 1, 1997 to December 31, 2005." (Cohn testimony in QRO, p.22)

Q. IS THE $22 MILLION PER YEAR ACTUALLY AN UNDERCOLLECTION?

A. No. A more accurate description would state that the Company will collect $22 million less in base rates than it would have if the higher estimate of fuel costs was rolled-in. The Company does not know what its energy costs will be from 1/1/97 to 12/31/2005. From 1/1/97 forwards, the Company would not charge an ECA. We agree that the Company's base rates would have collected approximately $22 million more per year if an additional

$.007 had been rolled-in the base rates.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE COLLECTION OF THESE COSTS?

A. No. The Tentative Order specifically denied the Company's request that it be granted a "right" and an "entitlement" to recover these undercollections and interest on them. The Commission also declined to rule on the accuracy of these undercollections. The Order did recognize that the Company had a right to "defer these costs and to file for recovery of these undercollections in the future." (Tentative Order p.6) The Commission's Corrected Opinion and Order clarified this point when it stated "we did not . . . decide that the differential is an appropriate component of PECO's transition or stranded cost. Both the recovery and the amount of this item should be addressed in PECO's restructuring proceeding . . ." (Corrected Order, p. 8-9)

Q. DO YOU FIND THAT THE COMPANY SHOULD BE ALLOWED TO INCLUDE THIS PROJECTED "UNDERCOLLECTION" IN THE CTC?

A. No. I have several disputes with the Company's requested treatment of these dollars. First is the nature of the $22 million annual claimed undercollection. It is accurate that the Company will collect approximately $22 million less per year than if an additional $.007 had been rolled-in to base rates. This is not the same as a projection that the Company would undercollect fuel costs in the future by $22 million per year because of the elimination of the fuel clause and the simultaneous rolling-in to base rates of an amount, $.0128, that was less than the <u>average</u> fuel costs over the period 2/93 to 12/31/96 (less Salem replacement power costs) by $.007. Second, in the 4 ECA's which cover this period, the average fuel cost ranged from a high of $.012322 to a low of $.010193. The Company has not established that this average is an accurate estimate of either current or future fuel costs. Third, by definition future deferred costs are not known. In traditional ratemaking, utilities are allowed to recover uncollected costs only when and in the exact amount in which they are uncollected. It is inconsistent with both traditional ratemaking, the new statute, and also with an unregulated energy market to allow the Company to bill customers for costs which are not known and which they *might* not have recovered in the future.

Q. WHAT WILL BE THE TREATMENT OF THESE COSTS AFTER RETAIL COMPETITION IS INTRODUCED?

A. After January 1, 1999, traditional regulation will not be applicable to fuel costs or any other component of generation costs. If the estimate of fuel costs that is contained in the market price study is correct, the Company will recover its full fuel costs. If actual fuel costs turn out to be lower than forecast, without any impact on the market price, the Company will collect more revenues than had been projected. The traditional ratemaking view would be that the Company had overcollected fuel costs. If fuel costs turn out to be higher than projected, either the Company would undercollect (from the standpoint of traditional ratemaking), or it would come in front of the Commission and request an adjustment to its generation cap and an adjustment to the avoidable generation price. This description of the future described in the competition bill does not include any reconciliation of fuel costs after 1/1/99; reconciliation of fuel costs no longer has the same meaning in a competitive framework. For this reason, it is inappropriate and inconsistent with the Commission's Order to allow the Company to collect through the CTC the "estimate" of undercollection of fuel costs. They are not yet uncollected and the estimate may prove to be totally wrong.

Q. WHAT TREATMENT OF THESE DOLLARS ARE YOU RECOMMENDING?

A. The Company has not yet demonstrated that these costs will be unrecovered and prudently incurred. I have included in stranded cost the estimate of fuel related deferred costs presented in the testimony of OCA witness Catlin.

Q. THE COMPANY IS REQUESTING THAT IT BE ALLOWED TO INCLUDE IN STRANDED COSTS ITS ESTIMATE OF WHAT IT WILL COST TO DECOMMISSION FOSSIL FUEL UNITS. DO YOU SUPPORT THIS INCLUSION?

A. No. These costs simply do not fit the definition of stranded costs. There is no distinction between a regulatory and a competitive environment that would prevent these costs from being recovered in a competitive environment.

Q. WHAT ARE THESE COSTS?

A. These costs are supposed to represent the cost of dismantling fossil fuel units at the end of the generating lives. As is evidenced by discovery response, it is not normal practice to "decommission" fossil units. It is not clear why the units would be dismantled. The Company has not presented evidence that these plants must be decommissioned. If they are dismantled in order to use the sites for other purposes, the sites must have enough value to make it worth dismantling them.

Q. IF IT WERE REQUIRED THAT FOSSIL UNITS BE DISMANTLED, WOULD THIS CHANGE YOUR OPINION?

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

Q. MR. CATLIN HAS TESTIFIED REGARDING THE APPROPRIATE AMOUNT OF FOSSIL DECOMMISSIONING. HOW DOES HIS TESTIMONY RELATE TO YOURS?

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

<u>IV. Sharing of stranded cost between stockholders and ratepayers</u>

Q. HOW HAS THE COMPANY PROPOSED THAT STRANDED COSTS BE SHARED?

A. Having estimated the total amount of generation assets that are stranded, the Company then has requested that ratepayers repay the full amount of this stranded cost and in addition pay a return on the unamortized balanced of this stranded cost. In other words, the Company is asking ratepayers not for only the $6.8 billion that they have identified as stranded cost, but for nearly $1.8 billion dollars in return on the unamortized portion of these stranded costs. The Company's actual recovery from ratepayers would be $8.6 billion.

Q. WHAT IS YOUR PROPOSAL FOR THE SHARING OF STRANDED UTILITY-OWNED GENERATION COSTS?

A. The Company's approach is unacceptable. It is inconsistent with past ratemaking policy in Pennsylvania, which has not allowed a return on plant which was not used and useful. Stranded generating plant is not used and useful; it is not providing benefits to ratepayers. Stockholders, who have been in a position to influence the Company's past investments, and who have benefited from profitable investments, should bear some of the cost of stranded investments. Costs will be shared if the Commission does not include a return on stranded costs in the CTC that will be paid by ratepayers.

Q. ARE YOU ARGUING THAT THE COMPANY SHOULD NOT BE ALLOWED TO EARN A RETURN ON ITS GENERATING ASSETS?

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

The Company has the ability to use its expertise in the generation business in a number of ways. The ability to conduct various nonregulated business has been acquired with the support of ratepayers. PECO currently is advising utilities in other parts of the country on nuclear operations; it is actively marketing power in other regions. PECO is a member of the New England Power Pool, and has begun to market power in New England. The June 2, 1997 "Electric Utility Week" reports on a number of ventures that PECO is undertaking, which are intended to earn profits that will not provide benefits to firm ratepayers. 1) PECO is purchasing a 288 MW share of the River Bend nuclear plant. 2) PECO is creating a new business unit which "will build on its wholesale marketing effort, which covers 46 states." 3) The existing PECO Energy Partners has acquired and will operate power plants at the sites of big customers. 4) The Company has an unregulated subsidiary called Exelon which offers efficiency, facility operation and fuel management services. 5) There will also be a unit to manage corporate business opportunities. This is all part of a "new strategic direction."(P.6) All of these sources of income exist because of expertise that has been acquired while functioning as a regulated generating utility, and would not have been possible if the Company had not had a production function.

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

Q. DOES THE SHARING OF UNECONOMIC COSTS BALANCE RISKS AND COMPETITIVE OPPORTUNITY?

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

Q. HOW WILL THE COMPANY HAVE OTHER OPPORTUNITIES TO EARN IN THE FUTURE FROM ITS GENERATION ASSETS?

A. There are a number of other potential sources of value. The Company's estimate assumes that generating assets have no "going concern" value, for which buyers may be willing to pay more than future earnings. The Company believes that "its name...may be of value." (Enron-1-7). The stranded cost computation does not reflect potential recoveries from Westinghouse resulting from the suit over the Salem generators (PAIEUG-V-16). Another potential benefit to stockholders would be a decline in the Pennsylvania Capital Stock Tax. (PAIEUG-V-20).

Q. HAVEN'T YOU ALREADY REFLECTED SITE VALUE IN YOUR ESTIMATE OF MITIGATION?

A. Our estimate of site value clearly does not reflect the full value of location and permitting. We expect that for the most part the Company will be able to sell generating sites for more than our estimates.

Q. WHAT OTHER FACTORS COULD INCREASE THE VALUE OF THE GENERATING ASSETS?

A. Simply offering the units in the competitive market will bring forth the buyers that believe the units have more value. It is clear that potential purchasers have different perceptions of the future profitability of generating assets. According to published reports PECO is seriously considering purchasing the Maine Yankee nuclear unit, which the current owners have almost decided will not be economic. The value of PECO's assets is not what PECO would pay for them, but what the highest bidder would pay. The Company's valuation assumes that no potential buyer has an estimate of future market price that is higher than

PECO's. PECO's own studies illustrate that there are substantial differences in projections of future prices. Even if there was no difference of opinion about future market prices, and therefore about market revenues, there may also be potential purchasers who would believe that they could improve unit performance or reduce expenses, or that the potential revenue enhancement from life extension is greater than the Company's assumption.

Q. THE COMPANY HAS ARGUED THAT IT WILL BEAR GREATER RISK IN THE FUTURE WHILE CUSTOMERS ARE EXPOSED TO LESS RISK. DO YOU AGREE WITH THIS ARGUMENT?

A. No. The security of being granted stranded cost recovery through a CTC has real value to the Company. In the past, regulation has allowed utilities an opportunity to recover the costs of generating plant, including a return on such plant, but has not guaranteed such recovery. Poor performance, higher costs, lower sales, and a number of other factors put the "allowed" recovery at risk. Without authorization to charge a CTC to collect a specified value for stranded costs, stockholders will always be exposed to some degree of risk that these costs will not be collected. After being provided with a guaranteed collection through designation as collectible stranded costs (whether securitized or not), there is no such risk.

Moreover the company's claim that customers are fully protected under the rate cap is not correct. While the rate cap does provide an important protection for consumers and limits the ability of the company to charge higher rates during the stranded cost recovery period, there are exceptions to the rate cap. In particular, if there are significant increases in the unit rate of fuel that would not allow the company to earn a fair rate of return, the company may seek an exception to the rate cap. Thus for the major potential cause of generation market price change which is out of the Company's control, that is, fuel prices, there is a possibility of adjustment. The Company itself has some control over most other causes of change. If the Company can control a variable, it can prevent an erosion of its earnings and even increase those earnings. Ratepayers have no such ability.

## V. SUMMARY OF RECOMMENDATIONS ON STRANDED COST RECOVERY

Q. PLEASE EXPLAIN THE STRANDED COST COMPUTATION.

A. Stranded costs are intended to represent the dollars of past investment that the Company will be unable to collect in the new competitive electric market, in which generation revenues will be determined by the market cost of power. These include regulatory assets that have been approved for collection and the stranded cost of generation assets less mitigation. The stranded cost of generation determination begins with market revenues that have been estimated by Mr. Smith. From these we have subtracted ongoing production costs (including annual decommissioning amounts from Mr. Catlin). These include some costs which have been reduced by mitigation. Stranded costs do not include fossil unit decommissioning, which is not allowed. The net value of any marginal revenues which will be realized plus our estimate of other cost mitigation are subtracted from the net book value of generation plant to yield the estimated stranded cost of generation plant. To the stranded generation plant, we have added the regulatory asset amounts determined by Mr. Catlin. The resulting total stranded cost is $3.5 billion and is comprised of the following components (in 1999 $000):

| | |
|---|---|
| Stranded Generation Plant | $1,913.1 |
| Regulatory Assets | $1,583.6 |
| Other Transition Costs | $ 32.6 |
| TOTAL STRANDED COST | $3,529.3 |

This value contrasts to PECO's estimate of their stranded cost of $6.8 million. The

Company's overstatement of their stranded cost by $3.3 billion or more than 45% is the result of an artificially low market price estimate and the inclusion of regulatory assets not properly classified as recoverable stranded costs.

Q. WOULD YOU PLEASE SUMMARIZE THE STRANDED COST RECOVERY YOU ARE PROPOSING.

A. Yes, based on the adjustment to market price, regulatory assets and decommissioning costs, PECO would fully recover its stranded costs if it were allowed to include the $ 3.5 Billion in its rates over the seven year period, 1999 - 2005. The OCA is proposing that the net $3.5 Billion value of the stranded costs be allowed recovery; but as is consistent with traditional regulation applicable to assets not used and useful, the Company should not be allowed any return on the stranded generation plant. Thus, the CTC charge to collect the $3.5 Billion stranded cost on a levelized basis is $526.9 million/year. This proposal contrasts with the Company's request for a full return on, as well as of, all stranded generation assets. We believe the denial of the return on the stranded generation costs is more consistent with both regulation and the applicable legislation.

Q. PLEASE SUMMARIZE THE DIFFERENCES BETWEEN YOUR RECOMMENDED STRANDED COST AND CTC RECOVERY AND THE COMPANY'S.

A. First, we believe the Company has overstated their stranded assets by a large amount. As a result, they have overestimated the return that would result from allowing a return on these assets. They have also calculated the return at too high a level, compared to the return allowed by the Commission in the securitization case. Finally, we believe that it is not just and reasonable to allow a return on generation assets which are stranded, and therefore not providing value to customers.

Q. WHAT IS THE REDUCTION IN THE TOTAL AMOUNT TO BE COLLECTED THROUGH THE CTC?

A. The proposed disallowance of stranded cost from the Company's claim, consisting of the return on stranded plant and a lower return on some regulatory assets, is $1639.8 million. In addition, the CTC will be lower because of the reduction in regulatory assets and the reduction in the stranded generation assets. The total to be collected through the CTC is $4.9 billion less than PECO has requested. The reduction in the stranded generation assets does not necessarily reduce the total amounts received by the Company over time because it is reflected in higher market generation prices over the life of the Company's assets. The major portion of the difference in CTC collection is due more to the overstatement of stranded cost than to the proposed disallowance. It is our position that the Company misstated its stranded cost, which caused a request for too large an amount of return, and that it also overstated its regulatory assets. If the original CTC computations had been based on our $1.9 billion stranded generating assets and our $1.5 billion of regulatory assets, the disallowance would have been only $594.3 million of return. This amount represents a fair sharing of the risks between investors and customers. The reconciliation between the PECO request and the OCA proposal is $4.9 billion, as shown in Table 1. Backup to this table is provided in Exhibit RLC-2.

**Table 1**

Comparison of Estimated Stranded Cost and Recovery

as of January 1, 1999

| *all values in millions, 1999 dollars* | OCA Proposal | PECO Request | *Difference* |
|---|---|---|---|
| Generating Plant | $6,628.0 | $6,688.4 | *($60.4)* |
| Less: Market Value | ($4,714.9) | ($2,862.9) | *($1,852.0)* |
| Stranded Generating Plant | $1,913.1 | $3,825.5 | *($1,912.4)* |
| Regulatory Assets | $1,583.6 | $2,583.7 | *($1,000.2)* |
| Additional Decommissioning | $0.0 | $363.5 | *($363.5)* |
| Other Transition Costs | $32.6 | $32.6 | *$0.0* |
| **ESTIMATED STRANDED COST** | **$3,529.3** | **$6,805.4** | ***($3,276.1)*** |
| NPV Return on Stranded Generating Plant | $594.3 | $1,604.0 | *($1,099.7)* |
| NPV Return on Regulatory Assets | $155.9 | $191.7 | *($35.8)* |
| Disallowance of Return | $594.4 | $0.0 | *($605.8)* |
| **PROPOSED RECOVERY** | **$3,685.3** | **$8,601.2** | ***($4,915.9)*** |

Q. DOES YOUR PROPOSAL REFLECT THE SECURITIZATION OF ANY STRANDED COSTS?

A. No. Like the Company's own filing in this case, I have made no provision for the fact that the Commission has approved securitization of approximately $1.1 billion of stranded costs, including approximately $600 million of PECO-owned generating assets.

My testimony does, however, demonstrate one of the problems with the premature securitization of generating assets that was allowed in that case. In my testimony I have essentially agreed that PECO has more than $600 million in stranded generating assets that may be recovered from ratepayers. I have also testified, however, that, consistent with Pennsylvania practice, it is unjust and unreasonable for PECO to charge ratepayers a return on those costs. Nevertheless, the Commission already has approved securitization which forces PECO ratepayers to pay a return (albeit on a somewhat lower securitized return)on these costs.

Securitization should only be permitted where it will <u>reduce</u> costs to ratepayers. Yet, here, securitization will actually <u>increase</u> costs to ratepayers by $160 million as compared to the appropriate ratemaking treatment of this $600 million in generating plant stranded costs.

Q. WHAT DO YOU PROPOSE AT THIS POINT?

A. It is my understanding that the securitization order is being appealed by a number of parties to that case including the OCA. If the Commission Order regarding securitization of stranded generating assets is not reversed, then I would recommend that the Commission reduce the Company's stranded cost claim in this case by $160 million to ensure that consumers do not pay more as a result of securitization than they would otherwise pay.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does.

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Exhibit RLC-1

**RICHARD LA CAPRA**

LA CAPRA ASSOCIATES
Principal

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

Mr. La Capra's professional accomplishments include:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

EDUCATIONAL BACKGROUND:

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

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# PECO Energy Company

## Summary of Stranded Costs

| $000 | | OCA | Exh. TPH-7 | Difference | % Diff. |
|---|---|---|---|---|---|
| Net Generating Plant & CWIP | | $6,627,965 | $6,688,384 | ($60,419) | -0.9% |
| Less: Market Value | | ($4,714,880) | ($2,862,913) | ($1,851,967) | 64.7% |
| Stranded Generating Plant | | $1,913,085 | $3,825,471 | ($1,912,386) | -50.0% |
| Regulatory Assets | [1] | $1,588,902 | $2,589,057 | ($1,000,155) | -38.6% |
| Regulatory Liabilities | | ($5,319) | ($5,319) | $0 | 0.0% |
| NUG Contracts | | $0 | $0 | $0 | N/A |
| Nuclear Decommissioning | [2] | $0 | $236,929 | ($236,929) | -100.0% |
| Fossil Decommissioning | | $0 | $126,605 | ($126,605) | -100.0% |
| Other Transition Cost | | $32,661 | $32,661 | $0 | 0.0% |
| **Total Stranded Cost** | | **$3,529,329** | **$6,805,404** | **($3,276,075)** | -48.1% |
| NPV Return on Stranded Gen. | [3] | $594,293 | $1,604,021 | ($1,009,728) | -62.9% |
| NPV Return on Reg. Assets | | | | | |
| Regulatory Assets | | $86,739 | $107,195 | ($20,457) | -19.1% |
| Unamort. Loss on Reacq. Debt | | $40,792 | $40,792 | $0 | 0.0% |
| Def. Fuel | | $28,411 | $43,746 | ($15,335) | -35.1% |
| Total NPV Return | | $155,942 | $191,733 | ($35,792) | -18.7% |
| Disallowance of Return | [4] | ($594,293) | $0 | ($594,293) | N/A |
| ***Proposed Recovery*** | | ***$3,685,271*** | ***$8,601,158*** | ***($4,915,888)*** | -57.2% |

**Notes:**

[1] Includes return on SFAS 109 Regulatory asset balance as provided by Mr. Catlin.

[2] OCA annual nuclear decommissioning fund contributions are reflected in the market value rather than as a separate stranded cost category.

[3] Net Present Value assumes levelized CTC recovery & end-of-year payments, discounted at the after-tax weighted average cost of capital of 7.53%.

[4] Disallowance equals return on stranded generating plant.

# PECO Energy Company

## Net Book Value of Generation Plant as of January 1, 1999
## Summary of Adjustments to Exhibit ABC-1

| *$000* | *Adjustment* | *Net Plant* |
| --- | --- | --- |
| Exhibit ABC-1 | | $6,688,384 |
| **Adjustments** | | |
| Exclude plant no longer used and useful as identified in the Bureau of Audits' report dated May 22, 1997 (excluding the adjustment for the Delaware plant) | ($35,419) | $6,652,965 |
| Adjust cost of land by inflation factor to reflect current value | ($25,000) | $6,627,965 |
| ***Adj. Net Book Value as of 1/1/99*** | | ***$6,627,965*** |
| ***Difference*** | | ***($60,419)*** |
| ***% increase/(decrease)*** | | ***-0.9%*** |

# PECO Energy Company

## Estimated NPV Contribution Margin ($000)

| $000 | OCA | Exh. TPH-5 | Diff. | % Diff. |
|---|---|---|---|---|
| Conemaugh | $361,028 | $274,250 | $86,778 | *31.6%* |
| Conowingo | $549,262 | $422,920 | $126,342 | *29.9%* |
| Cromby 1 | $0 | $0 | $0 | *N/A* |
| Cromby 2 | $0 | $0 | $0 | *N/A* |
| Delaware | $0 | $0 | $0 | *N/A* |
| Eddystone 1 | $6,422 | $0 | $6,422 | *N/A* |
| Eddystone 2 | $65,399 | $0 | $65,399 | *N/A* |
| Eddystone 3&4 | $133,130 | $38,237 | $94,893 | *248.2%* |
| Keystone | $268,064 | $195,899 | $72,165 | *36.8%* |
| Limerick 1 | $620,442 | $424,196 | $196,246 | *46.3%* |
| Limerick 2 | $826,504 | $405,469 | $421,035 | *103.8%* |
| Muddy Run | $225,463 | $153,609 | $71,854 | *46.8%* |
| Peach Bottom 2 | $151,084 | $66,767 | $84,317 | *126.3%* |
| Peach Bottom 3 | $160,656 | $71,985 | $88,671 | *123.2%* |
| Salem 1 | $98,050 | $22,449 | $75,601 | *336.8%* |
| Salem 2 | $125,309 | $36,958 | $88,351 | *239.1%* |
| Schuylkill | $0 | $0 | $0 | *N/A* |
| Combustion Turbines | $162,928 | $62,174 | $100,754 | *162.1%* |
| **Total NPV Margins** | **$3,753,741** | **$2,174,913** | **$1,578,828** | ***72.6%*** |
| Inventory & Working Capital | ($173,611) | ($173,611) | $0 | *0.0%* |
| Future Tax Depreciation Benefits | $328,078 | $305,947 | $22,131 | *7.2%* |
| Accum. Deferred ITC Benefits | $150,984 | $137,345 | $13,639 | *9.9%* |
| Deferred Income Tax | $655,687 | $418,318 | $237,369 | *56.7%* |
| **Total Adjusted NPV Margins** | **$4,714,880** | **$2,862,912** | **$1,851,968** | ***64.7%*** |

# PECO Energy Company

## Estimated Balance of Regulatory Assets as of December 31, 1998

| *$000* | *OCA* | *Exh. ABC-1* | *Difference* | *% Diff.* |
|---|---|---|---|---|
| CC on 50% Limerick Common | $175,812 | $175,812 | $0 | *0.0%* |
| Unamortized Loss on Reacq. Debt | $158,311 | $158,311 | $0 | *0.0%* |
| Nuclear Design Basis Document | $0 | $28,852 | ($28,852) | *-100.0%* |
| PB/Lim Water Chemistry System | $0 | $6,692 | ($6,692) | *-100.0%* |
| Limerick 1 Declaratory Order | $18,301 | $18,301 | $0 | *0.0%* |
| Limerick 2 Declaratory Order | $67,985 | $67,985 | $0 | *0.0%* |
| SFAS No. 106 | $32,615 | $100,580 | ($67,965) | *-67.6%* |
| SFAS No. 109 [1] | $992,561 | $1,687,069 | ($694,508) | *-41.2%* |
| Compensated Absences | $16,587 | $16,587 | $0 | *0.0%* |
| CC on 50% Comm PB/Sal/Eddy | $17,400 | $17,400 | $0 | *0.0%* |
| Electric Fuel Deferral 1996 | $109,330 | $109,330 | $0 | *0.0%* |
| Additional Fuel Deferral | $0 | $202,138 | ($202,138) | *-100.0%* |
| **Total Regulatory Assets** | **$1,588,902** | **$2,589,057** | **($1,000,155)** | ***-38.6%*** |
| **Exhibit ABC-1 Total** | | **$2,589,057** | | |

[1] Includes return on unamortized balance when collected over 7-year period.

# PECO Energy Company

## Annual CTC Revenue Requirements ($000)

## Summary

| Year | Components with Return Of & On | Unamort Loss on Reacq Debt | Components with Return Of | Deferred Fuel | Total Annual Rev. Req. | Exhibit ABC-1 Schedule 10 |
|---|---|---|---|---|---|---|
| **Exh. ABC-1, Sch. 10** | | | | | | |
| 1999 | $1,051,827 | $34,442 | $329,629 | $52,266 | $1,468,164 | $1,468,164 |
| 2000 | $984,061 | $32,752 | $329,630 | $52,266 | $1,398,709 | $1,398,709 |
| 2001 | $916,294 | $31,063 | $329,631 | $52,266 | $1,329,253 | $1,329,253 |
| 2002 | $848,527 | $29,373 | $329,632 | $52,266 | $1,259,798 | $1,259,798 |
| 2003 | $780,760 | $27,684 | $329,633 | $52,266 | $1,190,343 | $1,190,343 |
| 2004 | $712,993 | $25,995 | $329,634 | $52,266 | $1,120,888 | $1,120,888 |
| 2005 | $645,226 | $24,305 | $329,635 | $52,266 | $1,051,432 | $1,051,432 |
| Levelized | $882,884 | $29,858 | $329,632 | $52,266 | $1,294,640 | $1,331,508 |
| **OCA Stranded Cost Estimate** | | | | | | *Incr. Diff.* |
| 1999 | $490,689 | $34,442 | $165,816 | $20,663 | $711,609 | ($756,555) |
| 2000 | $463,467 | $32,752 | $165,816 | $20,663 | $682,698 | ($716,010) |
| 2001 | $436,246 | $31,063 | $165,816 | $20,663 | $653,788 | ($675,466) |
| 2002 | $409,025 | $29,373 | $165,816 | $20,663 | $624,877 | ($634,921) |
| 2003 | $381,804 | $27,684 | $165,816 | $20,663 | $595,966 | ($594,377) |
| 2004 | $354,582 | $25,995 | $165,816 | $20,663 | $567,056 | ($553,832) |
| 2005 | $327,361 | $24,305 | $165,816 | $20,663 | $538,145 | ($513,287) |
| Levelized | $421,611 | $29,858 | $165,816 | $20,663 | $637,948 | ($656,692) |
| **OCA Stranded Cost Estimate, excluding return on stranded gen. plant** | | | | | | *Incr. Diff.* |
| 1999 | $325,006 | $34,442 | $165,816 | $15,619 | $540,882 | ($170,727) |
| 2000 | $321,454 | $32,752 | $165,816 | $15,619 | $535,640 | ($147,058) |
| 2001 | $317,901 | $31,063 | $165,816 | $15,619 | $530,399 | ($123,389) |
| 2002 | $314,349 | $29,373 | $165,816 | $15,619 | $525,157 | ($99,720) |
| 2003 | $310,797 | $27,684 | $165,816 | $15,619 | $519,915 | ($76,051) |
| 2004 | $307,244 | $25,995 | $165,816 | $15,619 | $514,673 | ($52,382) |
| 2005 | $303,692 | $24,305 | $165,816 | $15,619 | $509,432 | ($28,713) |
| Levelized | $315,611 | $29,858 | $165,816 | $15,619 | $526,903 | ($111,045) |

# PECO Energy Company

## Annual CTC Revenue Requirements ($000)
## for Components with Return Of & On

| Year | Stranded Net Plant | Regulatory Liabilities | CC on 50% Lim Common | CC on 50% PB/Sal/Eddy Common | Nuc Design Basis Doc. | Accum. Deferred Taxes | Base for Return | Return @ | Annual Amort. | Annual Rev. Req. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Exh. ABC-1, Sch. 10** | | | | | | | | 13.71% | | |
| 1999 | $3,825,471 | ($5,319) | $175,812 | $17,400 | $28,852 | $582,202 | $3,460,014 | $474,368 | $577,459 | $1,051,827 |
| 2000 | $3,278,975 | ($4,559) | $150,696 | $14,914 | $24,730 | $499,030 | $2,965,726 | $406,601 | $577,459 | $984,061 |
| 2001 | $2,732,479 | ($3,799) | $125,580 | $12,429 | $20,609 | $415,859 | $2,471,439 | $338,834 | $577,459 | $916,294 |
| 2002 | $2,185,983 | ($3,039) | $100,464 | $9,943 | $16,487 | $332,687 | $1,977,151 | $271,067 | $577,459 | $848,527 |
| 2003 | $1,639,488 | ($2,280) | $75,348 | $7,457 | $12,365 | $249,515 | $1,482,863 | $203,301 | $577,459 | $780,760 |
| 2004 | $1,092,992 | ($1,520) | $50,232 | $4,971 | $8,243 | $166,343 | $988,575 | $135,534 | $577,459 | $712,993 |
| 2005 | $546,496 | ($760) | $25,116 | $2,486 | $4,122 | $83,172 | $494,288 | $67,767 | $577,459 | $645,226 |
| **OCA Stranded Cost Estimate** | | | | | | | | 12.87% | | |
| 1999 | $1,913,085 | ($5,319) | $175,812 | $17,400 | $0 | $625,729 | $1,480,568 | $190,549 | $300,140 | $490,689 |
| 2000 | $1,639,787 | ($4,559) | $150,696 | $14,914 | $0 | $536,339 | $1,269,058 | $163,328 | $300,140 | $463,467 |
| 2001 | $1,366,489 | ($3,799) | $125,580 | $12,429 | $0 | $446,950 | $1,057,548 | $136,106 | $300,140 | $436,246 |
| 2002 | $1,093,191 | ($3,039) | $100,464 | $9,943 | $0 | $357,560 | $846,039 | $108,885 | $300,140 | $409,025 |
| 2003 | $819,894 | ($2,280) | $75,348 | $7,457 | $0 | $268,170 | $634,529 | $81,664 | $300,140 | $381,804 |
| 2004 | $546,596 | ($1,520) | $50,232 | $4,971 | $0 | $178,780 | $423,019 | $54,443 | $300,140 | $354,582 |
| 2005 | $273,298 | ($760) | $25,116 | $2,486 | $0 | $89,390 | $211,510 | $27,221 | $300,140 | $327,361 |
| **OCA Stranded Cost Estimate, excluding return** | | | | | | | | 12.87% | | |
| 1999 | $1,913,085 | ($5,319) | $175,812 | $17,400 | $0 | $625,729 | $193,212 | $24,866 | $300,140 | $325,006 |
| 2000 | $1,639,787 | ($4,559) | $150,696 | $14,914 | $0 | $536,339 | $165,610 | $21,314 | $300,140 | $321,454 |
| 2001 | $1,366,489 | ($3,799) | $125,580 | $12,429 | $0 | $446,950 | $138,009 | $17,762 | $300,140 | $317,901 |
| 2002 | $1,093,191 | ($3,039) | $100,464 | $9,943 | $0 | $357,560 | $110,407 | $14,209 | $300,140 | $314,349 |
| 2003 | $819,894 | ($2,280) | $75,348 | $7,457 | $0 | $268,170 | $82,805 | $10,657 | $300,140 | $310,797 |
| 2004 | $546,596 | ($1,520) | $50,232 | $4,971 | $0 | $178,780 | $55,203 | $7,105 | $300,140 | $307,244 |
| 2005 | $273,298 | ($760) | $25,116 | $2,486 | $0 | $89,390 | $27,602 | $3,552 | $300,140 | $303,692 |

# PECO Energy Company

## Levelized CTC Revenue Requirements ($000)
## for Components with Return Of & On

| Year | Levelized Rev. Req. Net Gen. Plant | Stranded Net Gen. Plant | Net Gen. Plant Base for Return | Net Gen. Plant Return @ | Annual Amort. Net Gen. Plant | Levelized Rev. Req. Reg. Assets | Stranded Reg. Assets | Reg. Assets Base for Return | Reg. Assets Return @ | Annual Amort. Reg. Assets | Total Levelized Rev. Req. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Exh. ABC-1, Sch. 10 | | | | 13.71% | | | | | 13.71% | | |
| 1999 | $832,788 | $3,825,471 | $3,243,269 | $444,652 | $388,135 | $50,096 | $216,745 | $216,745 | $29,716 | $20,380 | $882,884 |
| 2000 | $832,788 | $3,437,336 | $2,938,305 | $402,842 | $429,946 | $50,096 | $196,365 | $196,365 | $26,922 | $23,175 | $882,884 |
| 2001 | $832,788 | $3,007,390 | $2,591,531 | $355,299 | $477,489 | $50,096 | $173,190 | $173,190 | $23,744 | $26,352 | $882,884 |
| 2002 | $832,788 | $2,529,901 | $2,197,214 | $301,238 | $531,550 | $50,096 | $146,838 | $146,838 | $20,131 | $29,965 | $882,884 |
| 2003 | $832,788 | $1,998,351 | $1,748,836 | $239,765 | $593,022 | $50,096 | $116,873 | $116,873 | $16,023 | $34,073 | $882,884 |
| 2004 | $832,788 | $1,405,329 | $1,238,986 | $169,865 | $662,923 | $50,096 | $82,800 | $82,800 | $11,352 | $38,744 | $882,884 |
| 2005 | $832,788 | $742,407 | $659,235 | $90,381 | $742,407 | $50,096 | $44,056 | $44,056 | $6,040 | $44,056 | $882,884 |
| | | | NPV @7.53% = | $1,604,021 | | | | NPV @7.53% = | $107,195 | | |
| OCA Stranded Cost Estimate | | | | 12.87% | | | | | 12.87% | | |
| 1999 | $379,298 | $1,913,085 | $1,287,356 | $165,683 | $213,615 | $42,313 | $187,893 | $187,893 | $24,182 | $18,131 | $421,611 |
| 2000 | $379,298 | $1,699,470 | $1,163,130 | $149,695 | $229,603 | $42,313 | $169,762 | $169,762 | $21,848 | $20,465 | $421,611 |
| 2001 | $379,298 | $1,469,866 | $1,022,917 | $131,649 | $247,649 | $42,313 | $149,297 | $149,297 | $19,215 | $23,098 | $421,611 |
| 2002 | $379,298 | $1,222,218 | $864,658 | $111,281 | $268,017 | $42,313 | $126,199 | $126,199 | $16,242 | $26,071 | $421,611 |
| 2003 | $379,298 | $954,201 | $686,031 | $88,292 | $291,006 | $42,313 | $100,128 | $100,128 | $12,886 | $29,426 | $421,611 |
| 2004 | $379,298 | $663,195 | $484,415 | $62,344 | $316,954 | $42,313 | $70,702 | $70,702 | $9,099 | $33,214 | $421,611 |
| 2005 | $379,298 | $346,241 | $256,851 | $33,057 | $346,241 | $42,313 | $37,488 | $37,488 | $4,825 | $37,488 | $421,611 |
| | | | NPV @7.53% = | $594,293 | | | | NPV @7.53% = | $86,739 | | |
| OCA Stranded Cost Estimate, excluding return | | | | 12.87% | | | | | 12.87% | | |
| 1999 | $273,298 | $1,913,085 | $0 | $0 | $273,298 | $42,313 | $187,893 | $187,893 | $24,182 | $18,131 | $315,611 |
| 2000 | $273,298 | $1,639,787 | $0 | $0 | $273,298 | $42,313 | $169,762 | $169,762 | $21,848 | $20,465 | $315,611 |
| 2001 | $273,298 | $1,366,489 | $0 | $0 | $273,298 | $42,313 | $149,297 | $149,297 | $19,215 | $23,098 | $315,611 |
| 2002 | $273,298 | $1,093,191 | $0 | $0 | $273,298 | $42,313 | $126,199 | $126,199 | $16,242 | $26,071 | $315,611 |
| 2003 | $273,298 | $819,894 | $0 | $0 | $273,298 | $42,313 | $100,128 | $100,128 | $12,886 | $29,426 | $315,611 |
| 2004 | $273,298 | $546,596 | $0 | $0 | $273,298 | $42,313 | $70,702 | $70,702 | $9,099 | $33,214 | $315,611 |
| 2005 | $273,298 | $273,298 | $0 | $0 | $273,298 | $42,313 | $37,488 | $37,488 | $4,825 | $37,488 | $315,611 |
| | | | NPV @7.53% = | $0 | | | | NPV @7.53% = | $86,739 | | |

# PECO Energy Company

## Annual & Levelized CTC Revenue Requirements ($000)
## Unamortized Loss on Reacquired Debt

| Year | Balance | Return @ | Annual Amort. | Annual Rev. Req. | Levelized Rev. Req. | Total Stranded Cost | Return @ | Annual Amort. |
|---|---|---|---|---|---|---|---|---|
| Exh. ABC-1, Sch. 10 | | 7.47% | | | | | 7.47% | |
| 1999 | $158,311 | $11,826 | $22,616 | $34,442 | $29,858 | $158,311 | $11,826 | $18,032 |
| 2000 | $135,695 | $10,136 | $22,616 | $32,752 | $29,858 | $140,279 | $10,479 | $19,379 |
| 2001 | $113,079 | $8,447 | $22,616 | $31,063 | $29,858 | $120,899 | $9,031 | $20,827 |
| 2002 | $90,463 | $6,758 | $22,616 | $29,373 | $29,858 | $100,072 | $7,475 | $22,383 |
| 2003 | $67,848 | $5,068 | $22,616 | $27,684 | $29,858 | $77,689 | $5,803 | $24,055 |
| 2004 | $45,232 | $3,379 | $22,616 | $25,995 | $29,858 | $53,635 | $4,007 | $25,852 |
| 2005 | $22,616 | $1,689 | $22,616 | $24,305 | $29,858 | $27,783 | $2,075 | $27,783 |
| | | | | | | NPV @7.53% = | $40,792 | |

# PECO Energy Company

Annual CTC Revenue Requirements ($000)
For Components with Only a Return Of

| Year | Nuclear Decom. | Fossil Decom. | PB/Lim Water Chemistry | SFAS 106 | SFAS 109 | Comp Absences | Lim 1 Decl. Order | Lim 2 Decl. Order | Other Transition Costs | Total Annual Rev. Req. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Exh. ABC-1, Sch. 10** | | | | | | | | | | |
| Beg. Balance | $236,929 | $126,605 | $6,692 | $100,580 | $1,687,069 | $16,587 | $18,301 | $67,985 | $32,661 | $2,293,409 |
| Annual Amort. | | | | | | | | | | |
| 1999 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,629 |
| 2000 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,630 |
| 2001 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,631 |
| 2002 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,632 |
| 2003 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,633 |
| 2004 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,634 |
| 2005 | $33,847 | $18,086 | $956 | $14,369 | $241,010 | $2,370 | $2,614 | $9,712 | $4,666 | $329,635 |
| **OCA Stranded Cost Estimate** | | | | | | | | | | |
| Beg. Balance | $0 | $0 | $0 | $32,615 | $992,561 | $16,587 | $18,301 | $67,985 | $32,661 | $1,160,710 |
| Annual Amort. | | | | | [1] | | | | | |
| 1999 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2000 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2001 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2002 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2003 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2004 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |
| 2005 | $0 | $0 | $0 | $4,659 | $141,794 | $2,370 | $2,614 | $9,712 | $4,666 | $165,816 |

[1] Includes return on unamortized balance.

# PECO Energy Company

## Annual & Levelized CTC Revenue Requirements ($000)

## Deferred Fuel Costs

| Year | Deferred Fuel Accrued thru 12/31/98 | Deferred Fuel Recoverable in Future | Total Annual Rev. Req. | Exhibit ABC-1 Schedule 10 | Levelized CTC Rev. Req. | Balance Def. Fuel w/return | Return @ | Annual Amort. Def. Fuel |
|---|---|---|---|---|---|---|---|---|
| **Exh. ABC-1, Sch. 10** | | | | | | | | |
| Beg. Balance | $157,468 | $154,000 | | | | | | |
| Discount Rate | 8.02% | 0.00% | | | | | 8.02% | |
| Annual Amort. w/return | | | | | | | | |
| 1999 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $157,468 | $12,629 | $17,637 |
| 2000 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $139,831 | $11,214 | $19,052 |
| 2001 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $120,779 | $9,687 | $20,579 |
| 2002 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $100,200 | $8,036 | $22,230 |
| 2003 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $77,970 | $6,253 | $24,013 |
| 2004 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $53,957 | $4,327 | $25,939 |
| 2005 | $30,266 | $22,000 | $52,266 | $52,266 | $30,266 | $28,019 | $2,247 | $28,019 |
| | | | | | | NPV @7.53% = | $43,746 | |
| **OCA Stranded Cost Estimate** | | | | | | | | |
| Beg. Balance | $109,330 | $0 | | | | | | |
| Discount Rate | 7.53% | 0.00% | | | | | 7.53% | |
| Annual Amort. | | | | | | | | |
| 1999 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $109,330 | $8,233 | $12,430 |
| 2000 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $96,900 | $7,297 | $13,366 |
| 2001 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $83,533 | $6,290 | $14,373 |
| 2002 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $69,160 | $5,208 | $15,455 |
| 2003 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $53,705 | $4,044 | $16,619 |
| 2004 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $37,086 | $2,793 | $17,870 |
| 2005 | $20,663 | $0 | $20,663 | $52,266 | $20,663 | $19,216 | $1,447 | $19,216 |
| | | | | | | NPV @7.53% = | $28,411 | |

R-00973953

OCA Statement No. 3

Phila. 10/14,15,16/97

E. Hilbert

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| | ) | |
| PECO ENERGY COMPANY | ) | DOCKET NO. R-00973953 |
| | ) | |

DIRECT TESTIMONY OF

THOMAS S. CATLIN

DOCUMENT FOLDER

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PROTHONOTARY'S OFFICE

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

DOCKETED

NOV 04 1997

JUNE 1997

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

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COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PECO ENERGY COMPANY | ) ) ) | DOCKET NO. R-00973953 |

## Direct Testimony of Thomas S. Catlin

### Introduction

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

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

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

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

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

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

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

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

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

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

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

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

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Schedules TSC-1 through TSC-3 are attached to my testimony. These schedules present my proposed adjustments to PECO's stranded cost claims.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. As shown on Schedule TSC-1, I have determined that the balance of regulatory assets to be included in stranded costs should be $1,346,592,000. This represents a reduction of $1,242,465,000 compared to PECO's claimed regulatory assets of $2,589,057,000. This reduction is due to adjustments to PECO's claim for nuclear design basis documentation costs, Peach Bottom and Limerick water chemistry system project costs, post-1996 electric fuel cost deferrals, SFAS No. 109 recoverable taxes, and SFAS No. 106 deferred costs.

In addition to the adjustments to regulatory assets summarized on Schedule TSC-1, I have also identified adjustments to PECO's claims for stranded decommissioning costs, both nuclear and fossil. With respect to nuclear decommissioning expense, I am proposing to modify PECO's claim based on the constant current accrual method and, instead, to recognize nuclear decommissioning costs by calculating the annual decommissioning trust fund accruals which will produce the monies necessary to fund decommissioning costs when they are projected to occur. These fund contributions are developed and summarized on Schedule TSC-2. As indicated there, the total required annual contributions are $29,162,000, based on the assumption that the Company's trust funds will no longer be tax qualified.

With respect to fossil decommissioning costs, it is the OCA's position, as discussed by Mr. Richard La Capra, that these costs should not be considered as an element of stranded costs at all. However, if the costs are to be recognized, I have determined that PECO has significantly overstated the appropriate amount to be included as a stranded cost. If fossil decommissioning costs are to be recognized, the appropriate allowance should be based on the present value of the projected future expenditures. As shown on Schedule TSC-3, the net present value of the future expenditures for fossil decommissioning is $61,839,000. In comparison, PECO has proposed to recover $125,605,000 of fossil decommissioning costs through the CTC over seven years with no return and another $22,150,000 of fossil decommissioning costs as an offset to the market value of generation.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

## Nuclear Decommissioning

Q. PLEASE SUMMARIZE PECO'S CLAIM FOR STRANDED COSTS ATTRIBUTABLE TO NUCLEAR DECOMMISSIONING.

A. PECO's claim for nuclear decommissioning costs is comprised of two components. The first component consists of what PECO argues is a deficiency in the balance of the decommissioning trust funds which will be available to pay the decommissioning costs to be accrued through 1998. PECO has treated this claimed deficiency as a direct stranded cost. The second component consists of the annual accruals necessary to fund decommissioning costs attributable to future service beginning in 1999. PECO has included these accruals as an O&M expense to be deducted from the market price of generation in calculating the market value of the Company's nuclear generating facilities. In turn, these future expense accruals further increase PECO's stranded costs.

Q. HOW DID THE COMPANY CALCULATE ITS CLAIMED DEFICIENCY IN THE AVAILABLE DECOMMISSIONING TRUST FUNDS?

A. PECO calculated its claimed deficiency in the balance of the nuclear decommissioning trust funds based on the "constant current accrual method." Under this method, the decommissioning cost of each nuclear unit in 1998 dollars is multiplied by the percentage of the life of that unit which will be completed as of 1998 to calculate a decommissioning fund balance which should exist as of the end of 1998. These calculated balances are then compared to the projected decommissioning trust fund balances for the various then compared to the projected decommissioning trust fund balances for the various nuclear units to derive fund deficiencies for each.

Q. HOW DID PECO CALCULATE THE ANNUAL EXPENSE ACCRUAL WHICH IT ATTRIBUTED TO FUTURE SERVICE?

A. To determine the expense accruals attributable to future service beginning in 1999, PECO first calculated the remaining decommissioning costs for each unit by subtracting the required fund balance at December 31, 1998 from the total decommissioning costs for that unit. PECO then escalated these remaining decommissioning costs for each generating unit to projected price levels in the year in which that generating unit is projected to be retired. Finally, the Company calculated the uniform annual payment or annuity required to fund that level of decommissioning costs by the retirement date. In determining this annuity, PECO utilized an assumed fund earnings rate of 6.5 percent. This earnings rate was based on the assumption that the future funding would be non-tax qualified.

Q. DO YOU AGREE WITH PECO'S PROPOSED TREATMENT OF NUCLEAR DECOMMISSIONING COSTS?

A. No, I do not. PECO's proposed treatment of nuclear decommissioning costs overstates stranded costs in two ways. The first overstatement results from the assumption that the current balance of the decommissioning trust fund for each nuclear unit must equal the total current decommissioning cost for that unit times the percentage of that unit's life which is complete. This assumption is inconsistent with the Company's own projections that decommissioning trust fund earnings will exceed the future inflation in nuclear decommissioning costs. As a result, PECO's claimed balance of stranded nuclear decommissioning costs of December 31, 1998 is overstated.

The second overstatement of stranded costs attributable to nuclear decommissioning expense stems from the manner in which PECO has calculated the decommissioning accruals related to future service. In particular, PECO has assumed that the full amount of the funds required to decommission each nuclear unit would have to be available on the date each unit is retired. This procedure fails to recognize that the decommissioning process and the associated expenditures for each unit will take place over a number of years. As a result, monies will remain in the decommissioning trust funds and those funds will continue to realize significant earnings during the period over which the decommissioning activities take place once the various units are retired. This causes the Company's claim for future nuclear decommissioning funding requirements to be overstated.

Q. HOW DO YOU PROPOSE TO CALCULATE THE APPROPRIATE ALLOWANCE FOR NUCLEAR DECOMMISSIONING COSTS?

A. I am proposing to modify PECO's calculations of the allowance for nuclear decommissioning costs to correct the two problems discussed above. That is, I am proposing to calculate the accruals necessary to fund decommissioning costs in a manner which accounts for the earnings on the existing trust fund balance for each nuclear unit and for the earnings which will be realized on the trust funds during the period over which the decommissioning activities for each unit take place.

To accomplish this, I have calculated the annual decommissioning funding accruals for each nuclear unit which, when added to the existing fund balance, will produce the monies necessary to pay for the costs of decommissioning that unit at the time the process occurs. In making these calculations, I have utilized a decommissioning model which takes into consideration the timing of the decommissioning expenditures. That is, I have recognized that inflation will continue to affect decommissioning costs over the period during which decommissioning takes place and that this, in turn, will increase the total decommissioning funds which are required. I have also recognized that the unexpended balances of the trust funds will continue to earn a return during the same time period.

Q. HOW HAVE YOU ACCOUNTED FOR WHAT PECO CLAIMS IS THE DEFICIENCY IN THE EXISTING TRUST FUND BALANCES?

A. The procedure or model which I have utilized to calculate future decommissioning accruals automatically takes into account any deficiency (or surplus) in the trust fund balance in determining the required annual fund contributions for each unit. To the extent that a deficiency does, in fact, exist, future annual contributions will be increased to make up that deficiency. If a surplus exists, the converse is true. As a result, it is not necessary to divide nuclear decommissioning costs into two components to determine stranded costs as PECO has done. The full effect of nuclear decommissioning costs on stranded costs is accounted for by the annual expense treated as a deduction from the market price of generation.

Q. HAS THE METHODOLOGY WHICH YOU ARE PROPOSING TO UTILIZE TO DETERMINE NUCLEAR DECOMMISSIONING EXPENSE BEEN ADOPTED PREVIOUSLY BY THIS COMMISSION?

A. Yes. The method which I am proposing to utilize to calculate the annual decommissioning accruals for PECO's nuclear units is the same procedure which I proposed on behalf of the OCA in Pennsylvania Power & Light Company's (PP&L's) last rate case at Docket No. R-00943271. In its Opinion and Order in that proceeding entered September 27, 1995, the Commission adopted this procedure for determining decommissioning expense. In its restructuring proceeding filed concurrently with this one, PP&L has factored nuclear decommissioning costs into the determination of stranded costs in the same manner which I have proposed here. That is, PP&L has treated the annual nuclear decommissioning funding requirements established in Docket No. R-00943271 as an annual expense to be offset against the market value of generation in the determination of its stranded costs. In addition, the method which I am proposing to utilize is also consistent with the Commission's Proposed Policy Statement on Nuclear Decommissioning Cost Estimation and Cost Recovery issued on July 18, 1996.

Q. WHAT FINANCIAL PARAMETERS DID YOU UTILIZE IN YOUR DETERMINATION OF THE ANNUAL DECOMMISSIONING ACCRUAL FOR EACH NUCLEAR UNIT?

A. In developing the annual decommissioning accruals for each nuclear unit, I have utilized the Company's current decommissioning cost estimates, cost escalation rates and fund earnings rates. In determining the decommissioning trust fund balances as of December 31, 1998, I made one change to the Company's projections. In its calculations of the fund balances as of December 31, 1998, PECO included earnings during 1997 and 1998 on the actual trust fund balances of December 31, 1996, but it did not include earnings during 1997 or 1998 on the amounts to be contributed to the funds during those two years. I have recalculated the December 31, 1998 balances to include interest to be earned during 1997 and 1998 not only on the beginning balance, but also on the amounts to be added to the funds during those years. In these calculations, I only included interest for the portion of the contributions which will be in the funds over the course of each year.

Q. HAVE YOU DEVELOPED A SCHEDULE WHICH SHOWS THE DECOMMISSIONING ACCRUALS AND FUND BALANCES FOR PECO'S VARIOUS NUCLEAR UNITS?

A. Yes. Schedule TSC-2 presents my findings regarding the decommissioning funding requirements for each of PECO's nuclear units. Pages 2 through 8 of this schedule provide the details for the various nuclear units. Page 1 of Schedule TSC-2 summarizes the annual contributions for PECO's seven nuclear units. As can be seen from this schedule, I have calculated the total nuclear decommissioning accruals to be $29,162,000 beginning in 1999. These requirements continue at this level through 2012. Beginning in 2013, the funding requirements begin to decline as the various nuclear units are retired.

Q. WHAT ASSUMPTION HAVE YOU MADE IN YOUR CALCULATIONS WITH REGARD TO THE TAX STATUS OF THE FUND CONTRIBUTIONS?

A. For purposes of my calculations of the total annual funding requirement of $29,162,000, I have accepted PECO's assumption that the funds will be non-tax qualified and have utilized PECO's corresponding earnings rate of 6.5 percent. To be conservative, I have applied the 6.5 percent rate not only to future amounts contributed to the trust funds, but also to the existing balances, most of which are tax qualified.

Q. HAVE YOU CALCULATED WHAT THE ANNUAL FUNDING REQUIREMENTS WOULD BE IF THE DECOMMISSIONING TRUST FUNDS WERE TO BE TAX QUALIFIED?

A. Yes. I have calculated the annual trust fund calculation which would be applicable for each unit based on PECO's assumption that the annual earnings rate for the funds would be 7.5 percent if the funds were tax qualified. Under, this scenario, the annual funding requirements for PECO's seven nuclear units would be $17,354,000.

## Fossil Decommissioning

Q. PLEASE SUMMARIZE PECO'S CLAIM FOR STRANDED COSTS ASSOCIATED WITH DECOMMISSIONING ITS FOSSIL FUEL GENERATING PLANTS.

A. Similar to its claim for stranded costs related to nuclear decommissioning, PECO's claim for fossil decommissioning related stranded costs consists of two components. The first component is the balance of fossil decommissioning costs which would have been accrued if the current estimate of decommissioning costs of each fossil plant had been accrued ratably over the projected service life of that plant from its in service date through December 31, 1998. This component was treated as a direct addition to stranded costs. The second component of PECO's claim is the annual accruals for future decommissioning costs beginning January 1, 1999. These annual accruals are equal to the current estimate of decommissioning costs for each unit (stated in 1998 dollars) divided by its projected life. These annual accruals were treated as a component of the operating expenses for each unit during its remaining life and, as such, deducted from the market price of generation in determining the market value of PECO's fossil generating assets.

Q. DO YOU AGREE WITH PECO'S PROPOSED TREATMENT OF FOSSIL GENERATING COSTS?

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

Q. PLEASE EXPLAIN WHY THE COMPANY'S PROPOSAL SHOULD NOT BE ACCEPTED EVEN IF THE COMMISSION DECIDES IT IS APPROPRIATE TO CONSIDER FOSSIL DECOMMISSIONING COSTS.

A. PECO's proposed treatment of fossil decommissioning costs results in the overstatement of stranded costs. PECO's procedure treats fossil decommissioning costs as though they were costs that are to be incurred today rather than in the future. It may be true that future costs will be greater than costs stated in today's dollars due to inflation. However, if PECO collected the dollars currently as it proposed, it would have to provide ratepayers a return on those dollars until the costs were actually incurred. Given that the Company's rate of return exceeds inflation, the net effect of offsetting the return against future inflation would be to significantly lower the costs to ratepayers.

Q. IF THE COMMISSION CHOOSES TO RECOGNIZE FOSSIL DECOMMISSIONING COSTS IN THE DETERMINATION OF STRANDED COSTS, HOW SHOULD THAT BE ACCOMPLISHED?

A. If the Commission decides to recognize fossil decommissioning costs, those costs should be treated in a manner consistent with what would take place under traditional regulation. Under traditional regulation, PECO would recover the costs of decommissioning its fossil plants through a net negative salvage allowance when and if the plants are decommissioned and the costs are actually incurred. Consistent with this, the stranded costs attributed to fossil decommissioning should be calculated by first escalating the estimated decommissioning costs for each fossil plant to the future cost levels at the time those costs are projected to be incurred. These future costs should then be discounted back to a net present value as of January 1, 1999 to obtain the stranded cost to be recovered from ratepayers.

Q. HAVE YOU PREPARED AN ESTIMATE OF STRANDED COSTS ASSOCIATED WITH FOSSIL DECOMMISSIONING COSTS BASED ON THIS PROCEDURE?

A. Yes. Schedule TSC-3 presents the calculation of stranded costs associated with fossil decommissioning costs based on this procedure. As shown on page 2 of Schedule TSC-3, I have started with the estimated current cost of decommissioning each fossil plant and have escalated the costs for each unit to projected cost levels at time the unit is projected to be decommissioned. Page 1 of Schedule TSC-3 shows the net present value of those future expenditures as of January 1, 1999 to be $61,839,000.

Q. WHAT COST ESTIMATES HAVE YOU UTILIZED IN THE CALCULATION OF THE STRANDED COSTS ASSOCIATED WITH FOSSIL DECOMMISSIONING UNDER THE NET PRESENT VALUE APPROACH?

A. I have utilized the current fossil decommissioning costs relied upon by PECO in its filing as the starting point for my analysis. However, I have adjusted those costs to eliminate the 15 to 16 percent contingency factor built into the cost estimates used by PECO. The elimination of the contingencies in fossil decommissioning costs is consistent with the Commission's Opinion and Order in PP&L's last rate at Docket No. R-00943271 to eliminate the contingencies built into PP&L's nuclear decommissioning costs estimates. As the Commission noted in that decision, there is no reason to conclude "... that speculative future costs necessitate a large contingency factor which rests, in itself, on total estimated costs which are themselves far from certain." (p. 82)

Q. WHAT OTHER PARAMETERS HAVE YOU UTILIZED TO CALCULATE THE NET PRESENT VALUE OF PECO'S CLAIMED FOSSIL DECOMMISSIONING COSTS?

A. To escalate the current estimates of the cost of decommissioning PECO's fossil plants to cost levels at the time those units are projected to be retired, I utilized PECO's estimate of the Gross Domestic Product Implicit Price Deflator (GDP-IPD) over the applicable time periods. In determining the timing of the decommissioning, I have utilized the projected retirement dates, including life extensions, which PECO utilized in its net market value analysis. I would note that for the Conemaugh, Eddystone and Keystone plants, these dates included 15 year life extensions which were not recognized in PECO's determination of decommissioning costs even though PECO included them in the market value analysis.

To determine the net present value of the future expenditures for each plant, as of January 1, 1999, I have utilized a discount rate of 7.53 percent. This is the discount rate adopted by the Commission in its May 22, 1997 Opinion and Qualified Rate Order with regard to PECO's securitization filing in Docket No. R-00973877. I would note that at PECO's claimed discount rate of 8.02 percent, the net present value of the future fossil decommissioning costs would be lower.

## Nuclear Design Basis Documentation

Q. WHAT CLAIM HAS PECO MADE FOR NUCLEAR DESIGN BASIS DOCUMENTATION?

A. PECO has proposed to include $28,852,000 in regulatory assets for the unamortized balance of nuclear design basis documentation costs. The purpose of the nuclear design basis documentation (NDBD) project was to develop documentation on the design basis of PECO's nuclear units to assist in the operation and inspection of the plants and to verify consistency with the actual plant configuration. Work on this project was initiated in 1989. However, the majority of the costs were incurred in 1991 through 1994.

Q. WHY ARE THESE COSTS RECORDED AS AN ASSET ON PECO'S BOOKS?

A. Initially, the NDBD project costs were recorded in Account No. 183-Preliminary survey and Investigation Charges. In 1992, PECO obtained approval of the Chief Accountant of the Federal Energy Regulatory Commission (FERC) to transfer these costs to Account No. 182.2, Unrecovered Plant and Regulatory Study Costs. These costs are being amortized to Account No. 407-Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE TREATMENT OF THE NDBD PROJECT COSTS?

A. I am proposing to eliminate the balance of deferred NDBD costs from the balance of regulatory assets included in stranded costs. PECO never sought nor obtained approval from the Pennsylvania PUC to defer these costs or to recover the costs in rates. The approval which PECO received from the FERC's Chief Accountant to include the balance of NDBD costs in Account No. 182.2 and to amortize the costs to Account No. 407 was an accounting approval only, and was not approval to recover the costs in rates. In fact, the Chief Accountant required the Company to write-off any portion of the costs which was not allowed for ratemaking.

The NDBD costs which PECO has claimed as a stranded cost were deferred outside of a rate case and primarily subsequent to PECO's last rate case. PECO has not provided any demonstration that these costs were incremental costs which were above the level of costs which the Commission allowed in the Company's last rate case. For example, the portion of NDBD costs attributable to Company labor may have been incurred by personnel whose wages were charged to O&M expenses in that rate case.

Peach Bottom and Limerick
Water Chemistry System Project Charges

Q. PLEASE SUMMARIZE PECO'S CLAIM FOR THE COSTS RELATED TO THE PEACH BOTTOM AND LIMERICK WATER CHEMISTRY SYSTEM PROJECT.

A. PECO has included the unamortized balance of costs associated with the Peach Bottom and Limerick water chemistry system project as a regulatory asset. The purpose of this project was to find a solution to the problem of intergranular stress corrosion cracking in the large bore piping which arose at nuclear plants in the 1980s. The work on this project was initiated at Peach Bottom in 1986 and then discontinued in 1987. Work at Peach Bottom was restarted in 1989 and again discontinued in 1992 when the project did not work as planned. The work at Limerick began in 1991 and was also suspended in 1992 due to the problems with the project at Peach Bottom. Work on the project was restarted in 1995. As with the nuclear design basis documentation costs, PECO received an order from the Chief Accountant of the FERC allowing it to record the costs in Account No. 182 and amortize the costs over the remaining lives of the plants. The projected unamortized balance of these costs as of December 31, 1998 is $6,692,000.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE TREATMENT OF THE WATER CHEMISTRY SYSTEM PROJECT COSTS?

A. I am proposing to eliminate the balance of unamortized water chemistry system project costs from the balance of regulatory assets to be recognized as stranded costs. My reasons for excluding these costs are the same as those for excluding NDBD costs from the balance of regulatory assets. That is, the Company never sought nor obtained approval to recover these costs in rates and the costs were deferred outside of a rate case with no demonstration that the costs were in excess of the level of costs allowed by the Commission in rates.

<u>Deferred Fuel</u>

Q. PLEASE SUMMARIZE PECO'S CLAIM WITH REGARD TO DEFERRED FUEL COSTS.

A. PECO has included $311,468,000 attributable to deferred fuel costs in its claimed balance of regulatory assets as of December 31, 1998. This balance is comprised of two components. The first component consists of the balance of unrecovered deferred fuel costs as of December 31, 1996 plus interest to December 31, 1998. This total amount included for this component is $109,330,000. The second component consists of projected fuel underrecoveries of $22 million per year during the period 1997 through 2005 plus interest on the 1997 and 1998 underrecoveries to December 31, 1998. The total balance of this second component which PECO has included as a regulatory asset is $202,138,000.

Q. WHAT IS THE OCA'S RECOMMENDATION WITH REGARD TO THE DEFERRED FUEL COSTS WHICH PECO HAS CLAIMED AS REGULATORY ASSETS?

A. The OCA does not dispute PECO's claim for the inclusion of the deferred fuel costs as of December 31, 1996 as a regulatory asset. However, as explained by OCA witness La Capra, the claimed deferrals for the period 1997 through 2005 should not be included as regulatory assets. Accordingly, I have reduced the Company's claimed regulatory assets by $202,138,000.

Q. IN ADDITION TO THE REASONS OFFERED BY MR. LA CAPRA AS TO WHY POST-1996 DEFERRED FUEL COSTS SHOULD NOT BE RECOGNIZED AS A REGULATORY ASSET, DO YOU HAVE ANY ADDITIONAL POINTS YOU WOULD LIKE TO RAISE?

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

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

A. According to the data presented on page A-1 of Exhibit TPH-1, the Company's pro forma rate of return is 9.88 percent and its pro forma return on equity is 11.26 percent. Including an additional $22 million of fuel expense in the cost of service instead of deferring it would reduce the Company's overall return by 15 basis points (.15%) and its return on equity by 30 basis points (.30%). Hence, even if these costs were included in rates, PECO's pro forma rates of return would remain well in excess of the rates of return which the Commission found applicable to PECO in its May 22, 1997 Opinion and Qualified Rate Order in Docket No. R-00973877.

Q. BY CITING PECO'S PRO FORMA RATES OF RETURN, DO YOU INTEND TO INDICATE YOUR AGREEMENT WITH THE COMPANY'S FINDINGS?

A. No. I believe that the Company has understated its pro forma rate of return. As examples, I disagree with the Company's adjustments to exclude purchases and sales of electricity for resale and to include PURTA taxes applicable to prior periods. However, I have not performed a detailed revenue requirement analysis in this proceeding.

SFAS No. 109 Recoverable Taxes

Q. PLEASE EXPLAIN WHAT THE BALANCE OF SFAS NO. 109 RECOVERABLE TAXES REPRESENTS.

A. Pursuant to Statement of Financial Accounting Standards No. 109 (SFAS No. 109), PECO is required to record its future tax liabilities on its balance sheet. The balance of SFAS No. 109 recoverable taxes represents the future tax obligation associated with tax-book timing differences for which the benefits were flowed through to ratepayers, rather than normalized. These taxes will become payable to the federal and state taxing authorities in the future as the timing differences reverse. Under the actual taxes paid doctrine which has been followed in Pennsylvania, these taxes would be recovered from ratepayers at the future time when they actually become due. Pursuant to the requirements of SFAS No. 109, the balance of recoverable taxes is "grossed up" to include the current state and federal taxes which will be paid on the revenue stream used to collect the future tax obligation.

Q. HOW HAS PECO TREATED THE BALANCE OF SFAS NO. 109 RECOVERABLE TAXES IN ITS DETERMINATION OF STRANDED COSTS?

A. PECO has included the nominal balance of SFAS No. 109 recoverable taxes in the amount of $1,687,069,000 as a regulatory asset. The Company has proposed to recover this balance by amortizing it on a straight line basis over the seven-year duration of its proposed CTC. Consistent with the fact that these recoverable taxes represent a future obligation and not an amount already expended, PECO has not included a return on the unrecovered balance of SFAS No. 109 taxes in calculating its CTC revenue requirement.

Q. IS PECO'S TREATMENT OF THE BALANCE OF SFAS NO. 109 RECOVERABLE TAXES APPROPRIATE?

A. No. What PECO is entitled to recover as part of its stranded costs is the present value of the revenue stream which it would receive under traditional regulation for the recovery of SFAS No. 109 recoverable taxes. That is, PECO is entitled to the present value of the revenues which it would collect over approximately the next 30 years as the tax-book timing differences underlying the balance of recoverable taxes reverse and those taxes come due.

Because PECO is not entitled to a return on the unrecovered balance of SFAS No. 109 recoverable taxes, the net present value of the revenue stream which PECO is entitled to receive over 30 years under traditional regulation is much less than the value of the revenue stream which PECO has claimed based on recovery of the balance over seven years. In other words, by proposing to recover the nominal balance of recoverable taxes over seven years, PECO has significantly accelerated the recovery of these taxes. As a result, the net present value of the revenue stream which PECO has requested is in excess of what it would receive under traditional regulation.

Q. HOW SHOULD THE REGULATORY ASSET ATTRIBUTABLE TO SFAS NO. 109 RECOVERABLE TAXES BE DETERMINED?

A. The regulatory asset attributable to SFAS No. 109 should be determined as the present value of the revenue stream to which PECO would be entitled over approximately the next 30 years under traditional regulation.

Q. HAVE YOU BEEN ABLE TO DETERMINE THE REVENUE STREAM WHICH PECO WOULD RECEIVE FOR THE RECOVERY OF SFAS NO. 109 TAXES UNDER TRADITIONAL REGULATION?

A. No. PECO has indicated that it does not maintain the information necessary to project when the future timing differences underlying the balance of SFAS No. 109 recoverable taxes will reverse. Hence, it was not possible to develop an accurate calculation of the actual revenue stream which PECO would receive under traditional regulation.

Q. HOW ARE YOU PROPOSING TO DETERMINE THE NET PRESENT VALUE OF PECO'S SFAS NO. 109 RECOVERABLE TAXES?

A. Based on the projected retirement dates including life extensions and the projected net investment as of December 31, 1998, the weighted average remaining life of PECO's generating stations is 27 years. Based on this, I am proposing to determine the net present value of PECO's SFAS No. 109 recoverable taxes based on recovery of those taxes at a uniform annual rate over years. Based on the discount rate of 7.53 percent adopted by the Commission in PECO's securitization proceeding, this results in a net present value of $750,251,000. It is this amount which I am proposing to reflect as a regulatory asset. In comparison, PECO's proposal to recover the SFAS No. 109 taxes over seven years results in a net present value of $1,275,212,000.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE REVERSAL OF THE TIMING DIFFERENCES UNDERLYING SFAS NO. 109 RECOVERABLE TAXES?

A. Yes. I would like to note that PECO did attempt to provide a projection of the pattern for the recovery of the SFAS No. 109 recoverable taxes. This projection reflected the reversing timing differences and, hence, the amount of the tax recovery being greatest in 1999 and declining through the year 2029. The expected pattern would be for the level of reversing timing differences to be relatively low initially and, generally, to increase over time. Given this inconsistency, I have not utilized PECO's projection and have instead assumed a uniform annual reversal over 25 years. If PECO is able to prepare a detailed analysis showing a more accurate pattern for the reversing timing differences, I would be willing to analyze that proposal and consider its use for purposes of my analysis.

<u>SFAS No. 106 Deferred Costs</u>

Q. WHAT CLAIM HAS PECO MADE FOR SFAS NO. 106 DEFERRED COSTS?

A. PECO has included as a regulatory asset $100,580,000 for deferred other post employment benefits (OPEBs) costs associated with the adoption of Statement of Financial Accounting Standard No. 106 (SFAS No. 106). This regulatory asset consists of two components. The first component is the unamortized balance of SFAS No. 106 costs which PECO deferred in the years 1993 and 1994 prior to the inclusion of these costs in rates. This deferral was accepted by the parties in a settlement approved by the Commission in its October 19, 1994 Order in Docket No. R-00922479. This component of PECO's claimed regulatory asset is $32,615,000.

The second component of PECO's claimed SFAS No. 106 regulatory asset is related to the Company's Voluntary Retirement Incentive Program (VRIP) and Voluntary

Separation Incentive Program (VSIP) offered in 1994. Under Generally Accepted Accounting Principles (GAAP), PECO would normally have been required to expense the entire OPEB transition obligation associated with employees accepting early retirement under these programs in 1994, rather than being allowed to continue to amortize them over an additional 18 years. However, because recovery of these costs in rates had already been agreed upon as a result of the above-referenced settlement in Docket No. R-00922479, PECO recorded a regulatory asset for the amount of the costs which otherwise would have had to have been expensed in 1994. The balance of this component of PECO's claimed regulatory asset is $67,965,000.

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU ARE PROPOSING TO MAKE TO PECO'S CLAIMED SFAS NO. 106 REGULATORY ASSET.

A. I am proposing to eliminate PECO's claimed regulatory asset for SFAS No. 106 costs deferred in conjunction with the 1994 VRIP and VSIP offerings. As explained above and also noted in Mr. Cohn's testimony on behalf of PECO (page 33), recovery of the VRIP and VSIP related transition obligation is already provided for in rates as part of the 20-year amortization of the Company's overall transition obligation. This amortization expense is included as a component of the Company's 1996 benefits costs per books. In turn, the 1996 benefits expenses have been included in the determination of the administrative and general expenses included in the determination of the net market value of PECO's generating assets. Therefore, the costs associated with the recovery of PECO's overall SFAS No. 106 transition obligation have already been accounted for. It is unnecessary to separately include the portion of that overall obligation related to employees who accepted the VSIP and VRIP offerings as a regulatory asset. To do so would result in a double count of these costs. Therefore, I have reduced the regulatory asset associated with SFAS No. 106 by $67,965,000 to exclude the VRIP/VSIP related balance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PECO ENERGY COMPANY | ) ) ) | DOCKET NO. R-00973953 |

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 1997

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PECO ENERGY COMPANY

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

| | Amount Per Company (1) | Amount Per OCA |
|---|---|---|
| Limerick Common Carrying Costs | $175,812 | $175,812 |
| Peach Bottom et.al. Common Carrying | 17,400 | 17,400 |
| Unamortized Loss on Reacquired Debt | 158,311 | 158,311 |
| Nuclear Design Basis Documentation | 28,852 | 0 |
| Water Chemistry System Project Costs | 6,692 | 0 |
| Limerick 1 Declaratory Order | 18,301 | 18,301 |
| Limerick 2 Declaratory Order | 67,985 | 67,985 |
| SFAS No. 106 Costs | 100,580 | 32,615 |
| SFAS No. 109 Recoverable Taxes | 1,687,069 | 750,251 |
| Compensated Absences | 16,587 | 16,587 |
| 1996 Electric Fuel Deferral | 109,330 | 109,330 |
| 1997-2005 Electric Fuel Deferrals | 202,138 | 0 |
| Total Regulatory Assets | $2,589,057 | $1,346,592 |

Note:
(1) Per PECO Exhibit ABC-1, Schedule 6.

PECO ENERGY COMPANY

Summary of OCA Recommended Nuclear Decommissioning
Funding Contributions and Payment Periods

| Nuclear Unit | Annual Contribution | Payment Period |
|---|---|---|
| Limerick 1 | $4,403,000 | 1999-2023 |
| Limmerick 2 | 8,043,000 | 1999-2028 |
| Salem 1 | 2,651,000 | 1999-2015 |
| Salem 2 | 2,509,000 | 1999-2019 |
| Peach Bottom 1 | 2,992,000 | 1999-2012 |
| Peach Bottom 2 | 2,588,000 | 1999-2012 |
| Peach Bottom 3 | 5,976,000 | 1999-2013 |
| | $29,162,000 | |

PECO ENERGY COMPANY

Limerick 1 Decommissioning Funding Analysis
($000)

| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
|---|---|---|---|---|---|---|---|---|
| | | | Decommioning Fund Details | | | | | |
| 1 | Beginning Balance | | | | | | | 68,731 |
| 2 | 1997 | 5,822 | 0.0750 | 5,822 | 5,562 | 11,384 | 0 | 80,115 |
| 3 | 1998 | 5,822 | 0.0750 | 5,822 | 6,446 | 12,268 | 0 | 92,383 |
| 4 | 1999 | 4,403 | 0.0650 | 4,403 | 6,334 | 10,737 | 0 | 103,120 |
| 5 | 2000 | 4,403 | 0.0650 | 4,403 | 7,054 | 11,457 | 0 | 114,577 |
| 6 | 2001 | 4,403 | 0.0650 | 4,403 | 7,821 | 12,224 | 0 | 126,800 |
| 7 | 2002 | 4,403 | 0.0650 | 4,403 | 8,639 | 13,042 | 0 | 139,843 |
| 8 | 2003 | 4,403 | 0.0650 | 4,403 | 9,513 | 13,916 | 0 | 153,759 |
| 9 | 2004 | 4,403 | 0.0650 | 4,403 | 10,445 | 14,848 | 0 | 168,607 |
| 10 | 2005 | 4,403 | 0.0650 | 4,403 | 11,439 | 15,842 | 0 | 184,449 |
| 11 | 2006 | 4,403 | 0.0650 | 4,403 | 12,500 | 16,903 | 0 | 201,352 |
| 12 | 2007 | 4,403 | 0.0650 | 4,403 | 13,632 | 18,035 | 0 | 219,388 |
| 13 | 2008 | 4,403 | 0.0650 | 4,403 | 14,840 | 19,243 | 0 | 238,631 |
| 14 | 2009 | 4,403 | 0.0650 | 4,403 | 16,129 | 20,532 | 0 | 259,163 |
| 15 | 2010 | 4,403 | 0.0650 | 4,403 | 17,504 | 21,907 | 0 | 281,070 |
| 16 | 2011 | 4,403 | 0.0650 | 4,403 | 18,971 | 23,374 | 0 | 304,444 |
| 17 | 2012 | 4,403 | 0.0650 | 4,403 | 20,537 | 24,940 | 0 | 329,384 |
| 18 | 2013 | 4,403 | 0.0650 | 4,403 | 22,207 | 26,610 | 0 | 355,994 |
| 19 | 2014 | 4,403 | 0.0650 | 4,403 | 23,989 | 28,392 | 0 | 384,386 |
| 20 | 2015 | 4,403 | 0.0650 | 4,403 | 25,890 | 30,293 | 0 | 414,679 |
| 21 | 2016 | 4,403 | 0.0650 | 4,403 | 27,919 | 32,322 | 0 | 447,002 |
| 22 | 2017 | 4,403 | 0.0650 | 4,403 | 30,084 | 34,487 | 0 | 481,489 |
| 23 | 2018 | 4,403 | 0.0650 | 4,403 | 32,394 | 36,797 | 0 | 518,285 |
| 24 | 2019 | 4,403 | 0.0650 | 4,403 | 34,858 | 39,261 | 0 | 557,546 |
| 25 | 2020 | 4,403 | 0.0650 | 4,403 | 37,487 | 41,890 | 0 | 599,437 |
| 26 | 2021 | 4,403 | 0.0650 | 4,403 | 40,293 | 44,696 | 0 | 644,133 |
| 27 | 2022 | 4,403 | 0.0650 | 4,403 | 43,286 | 47,689 | 0 | 691,822 |
| 28 | 2023 | 4,403 | 0.0650 | 4,403 | 46,480 | 50,883 | 0 | 742,705 |
| 29 | 2024 | 0 | 0.0650 | 0 | 49,361 | 49,361 | (11,337) | 780,728 |
| 30 | 2025 | 0 | 0.0650 | 0 | 50,141 | 50,141 | (64,083) | 766,786 |
| 31 | 2026 | 0 | 0.0650 | 0 | 45,240 | 45,240 | (182,562) | 629,463 |
| 32 | 2027 | 0 | 0.0650 | 0 | 33,955 | 33,955 | (244,917) | 418,502 |
| 33 | 2028 | 0 | 0.0650 | 0 | 19,487 | 19,487 | (255,066) | 182,922 |
| 34 | 2029 | 0 | 0.0650 | 0 | 8,057 | 8,057 | (125,236) | 65,743 |
| 35 | 2030 | 0 | 0.0650 | 0 | 4,346 | 4,346 | (1,700) | 68,389 |
| 36 | 2031 | 0 | 0.0650 | 0 | 4,521 | 4,521 | (1,764) | 71,146 |
| 37 | 2032 | 0 | 0.0650 | 0 | 4,703 | 4,703 | (1,833) | 74,017 |
| 38 | 2033 | 0 | 0.0650 | 0 | 4,893 | 4,893 | (1,899) | 77,011 |
| 39 | 2034 | 0 | 0.0650 | 0 | 4,275 | 4,275 | (26,360) | 54,927 |
| 40 | 2035 | 0 | 0.0650 | 0 | 1,781 | 1,781 | (56,654) | 55 |
| | | $121,720 | | $121,720 | $783,015 | $904,735 | ($973,411) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Limerick 2 Decommissioning Funding Analysis
($000)

| | | | Decommissioning Fund Details | | | | | |
|---|---|---|---|---|---|---|---|---|
| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
| 1 | Beginning Balance | | | | | | | 37,961 |
| 2 | 1997 | 4,762 | 0.0750 | 4,762 | 3,132 | 7,894 | 0 | 45,855 |
| 3 | 1998 | 4,762 | 0.0750 | 4,762 | 3,745 | 8,507 | 0 | 54,362 |
| 4 | 1999 | 8,043 | 0.0650 | 8,043 | 3,910 | 11,953 | 0 | 66,315 |
| 5 | 2000 | 8,043 | 0.0650 | 8,043 | 4,711 | 12,754 | 0 | 79,069 |
| 6 | 2001 | 8,043 | 0.0650 | 8,043 | 5,565 | 13,608 | 0 | 92,676 |
| 7 | 2002 | 8,043 | 0.0650 | 8,043 | 6,476 | 14,519 | 0 | 107,196 |
| 8 | 2003 | 8,043 | 0.0650 | 8,043 | 7,448 | 15,491 | 0 | 122,687 |
| 9 | 2004 | 8,043 | 0.0650 | 8,043 | 8,486 | 16,529 | 0 | 139,216 |
| 10 | 2005 | 8,043 | 0.0650 | 8,043 | 9,593 | 17,636 | 0 | 156,852 |
| 11 | 2006 | 8,043 | 0.0650 | 8,043 | 10,774 | 18,817 | 0 | 175,669 |
| 12 | 2007 | 8,043 | 0.0650 | 8,043 | 12,034 | 20,077 | 0 | 195,746 |
| 13 | 2008 | 8,043 | 0.0650 | 8,043 | 13,379 | 21,422 | 0 | 217,168 |
| 14 | 2009 | 8,043 | 0.0650 | 8,043 | 14,813 | 22,856 | 0 | 240,024 |
| 15 | 2010 | 8,043 | 0.0650 | 8,043 | 16,344 | 24,387 | 0 | 264,411 |
| 16 | 2011 | 8,043 | 0.0650 | 8,043 | 17,977 | 26,020 | 0 | 290,432 |
| 17 | 2012 | 8,043 | 0.0650 | 8,043 | 19,720 | 27,763 | 0 | 318,195 |
| 18 | 2013 | 8,043 | 0.0650 | 8,043 | 21,579 | 29,622 | 0 | 347,817 |
| 19 | 2014 | 8,043 | 0.0650 | 8,043 | 23,563 | 31,606 | 0 | 379,423 |
| 20 | 2015 | 8,043 | 0.0650 | 8,043 | 25,680 | 33,723 | 0 | 413,147 |
| 21 | 2016 | 8,043 | 0.0650 | 8,043 | 27,939 | 35,982 | 0 | 449,128 |
| 22 | 2017 | 8,043 | 0.0650 | 8,043 | 30,348 | 38,391 | 0 | 487,519 |
| 23 | 2018 | 8,043 | 0.0650 | 8,043 | 32,919 | 40,962 | 0 | 528,482 |
| 24 | 2019 | 8,043 | 0.0650 | 8,043 | 35,663 | 43,706 | 0 | 572,187 |
| 25 | 2020 | 8,043 | 0.0650 | 8,043 | 38,590 | 46,633 | 0 | 618,820 |
| 26 | 2021 | 8,043 | 0.0650 | 8,043 | 41,713 | 49,756 | 0 | 668,576 |
| 27 | 2022 | 8,043 | 0.0650 | 8,043 | 45,045 | 53,088 | 0 | 721,664 |
| 28 | 2023 | 8,043 | 0.0650 | 8,043 | 48,601 | 56,644 | 0 | 778,308 |
| 29 | 2024 | 8,043 | 0.0650 | 4,022 | 52,259 | 56,281 | 0 | 834,589 |
| 30 | 2025 | 8,043 | 0.0650 | 8,043 | 56,163 | 64,206 | 0 | 898,795 |
| 31 | 2026 | 8,043 | 0.0650 | 4,022 | 60,329 | 64,350 | 0 | 963,145 |
| 32 | 2027 | 8,043 | 0.0650 | 8,043 | 64,773 | 72,816 | 0 | 1,035,961 |
| 33 | 2028 | 8,043 | 0.0650 | 8,043 | 69,650 | 77,693 | 0 | 1,113,653 |
| 34 | 2029 | 0 | 0.0650 | 0 | 73,619 | 73,619 | (28,794) | 1,158,479 |
| 35 | 2030 | 0 | 0.0650 | 0 | 75,493 | 75,493 | (62,483) | 1,171,489 |
| 36 | 2031 | 0 | 0.0650 | 0 | 69,599 | 69,599 | (264,521) | 976,566 |
| 37 | 2032 | 0 | 0.0650 | 0 | 56,186 | 56,186 | (275,231) | 757,522 |
| 38 | 2033 | 0 | 0.0650 | 0 | 41,196 | 41,196 | (284,800) | 513,917 |
| 39 | 2034 | 0 | 0.0650 | 0 | 24,462 | 24,462 | (297,325) | 241,054 |
| 40 | 2035 | 0 | 0.0650 | 0 | 13,825 | 13,825 | (69,242) | 185,638 |
| 41 | 2036 | 0 | 0.0650 | 0 | 11,582 | 11,582 | (25,396) | 171,823 |
| 42 | 2037 | 0 | 0.0650 | 0 | 10,841 | 10,841 | (19,897) | 162,768 |
| 43 | 2038 | 0 | 0.0650 | 0 | 10,210 | 10,210 | (20,644) | 152,333 |
| 44 | 2039 | 0 | 0.0650 | 0 | 9,485 | 9,485 | (21,420) | 140,398 |
| 45 | 2040 | 0 | 0.0650 | 0 | 8,656 | 8,656 | (22,287) | 126,767 |
| 46 | 2041 | 0 | 0.0650 | 0 | 7,718 | 7,718 | (23,059) | 111,426 |
| 47 | 2042 | 0 | 0.0650 | 0 | 6,661 | 6,661 | (23,925) | 94,162 |
| 48 | 2043 | 0 | 0.0650 | 0 | 5,475 | 5,475 | (24,824) | 74,814 |
| 49 | 2044 | 0 | 0.0650 | 0 | 4,146 | 4,146 | (25,829) | 53,131 |
| 50 | 2045 | 0 | 0.0650 | 0 | 2,663 | 2,663 | (26,723) | 29,071 |
| 51 | 2046 | 0 | 0.0650 | 0 | 945 | 945 | (29,920) | 95 |
| | | 250,815 | | 242,772 | 1,265,683 | 1,508,455 | (1,546,320) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Salem Unit 1 Decommissioning Funding Analysis
($000)

| | | | Decommissioning Fund Details | | | | | |
|---|---|---|---|---|---|---|---|---|
| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
| 1 | Beginning Balance | | | | | | | 34,735 |
| 2 | 1997 | 1,961 | 0.0750 | 1,961 | 2,773 | 4,734 | 0 | 39,469 |
| 3 | 1998 | 1,961 | 0.0750 | 1,961 | 3,140 | 5,101 | 0 | 44,570 |
| 4 | 1999 | 2,651 | 0.0650 | 2,651 | 3,074 | 5,725 | 0 | 50,295 |
| 5 | 2000 | 2,651 | 0.0650 | 2,651 | 3,457 | 6,108 | 0 | 56,403 |
| 6 | 2001 | 2,651 | 0.0650 | 2,651 | 3,866 | 6,517 | 0 | 62,920 |
| 7 | 2002 | 2,651 | 0.0650 | 2,651 | 4,303 | 6,954 | 0 | 69,874 |
| 8 | 2003 | 2,651 | 0.0650 | 2,651 | 4,768 | 7,419 | 0 | 77,293 |
| 9 | 2004 | 2,651 | 0.0650 | 2,651 | 5,265 | 7,916 | 0 | 85,209 |
| 10 | 2005 | 2,651 | 0.0650 | 2,651 | 5,795 | 8,446 | 0 | 93,656 |
| 11 | 2006 | 2,651 | 0.0650 | 2,651 | 6,361 | 9,012 | 0 | 102,668 |
| 12 | 2007 | 2,651 | 0.0650 | 2,651 | 6,965 | 9,616 | 0 | 112,283 |
| 13 | 2008 | 2,651 | 0.0650 | 2,651 | 7,609 | 10,260 | 0 | 122,543 |
| 14 | 2009 | 2,651 | 0.0650 | 2,651 | 8,296 | 10,947 | 0 | 133,490 |
| 15 | 2010 | 2,651 | 0.0650 | 2,651 | 9,029 | 11,680 | 0 | 145,169 |
| 16 | 2011 | 2,651 | 0.0650 | 2,651 | 9,811 | 12,462 | 0 | 157,631 |
| 17 | 2012 | 2,651 | 0.0650 | 2,651 | 10,646 | 13,297 | 0 | 170,928 |
| 18 | 2013 | 2,651 | 0.0650 | 2,651 | 11,536 | 14,187 | 0 | 185,115 |
| 19 | 2014 | 2,651 | 0.0650 | 2,651 | 12,486 | 15,137 | 0 | 200,252 |
| 20 | 2015 | 2,651 | 0.0650 | 2,651 | 13,500 | 16,151 | 0 | 216,403 |
| 21 | 2016 | 0 | 0.0650 | 0 | 14,093 | 14,093 | (11,944) | 218,552 |
| 22 | 2017 | 0 | 0.0650 | 0 | 13,564 | 13,564 | (32,053) | 200,063 |
| 23 | 2018 | 0 | 0.0650 | 0 | 12,018 | 12,018 | (41,235) | 170,846 |
| 24 | 2019 | 0 | 0.0650 | 0 | 9,978 | 9,978 | (43,704) | 137,120 |
| 25 | 2020 | 0 | 0.0650 | 0 | 7,698 | 7,698 | (44,337) | 100,481 |
| 26 | 2021 | 0 | 0.0650 | 0 | 5,205 | 5,205 | (45,534) | 60,152 |
| 27 | 2022 | 0 | 0.0650 | 0 | 3,020 | 3,020 | (30,127) | 33,044 |
| 28 | 2023 | 0 | 0.0650 | 0 | 2,061 | 2,061 | (4,543) | 30,562 |
| 29 | 2024 | 0 | 0.0650 | 0 | 1,889 | 1,889 | (4,726) | 27,725 |
| 30 | 2025 | 0 | 0.0650 | 0 | 1,693 | 1,693 | (4,890) | 24,527 |
| 31 | 2026 | 0 | 0.0650 | 0 | 1,425 | 1,425 | (6,501) | 19,451 |
| 32 | 2027 | 0 | 0.0650 | 0 | 1,115 | 1,115 | (5,603) | 14,963 |
| 33 | 2028 | 0 | 0.0650 | 0 | 964 | 964 | (1,135) | 14,792 |
| 34 | 2029 | 0 | 0.0650 | 0 | 951 | 951 | (1,174) | 14,570 |
| 35 | 2030 | 0 | 0.0650 | 0 | 935 | 935 | (1,218) | 14,286 |
| 36 | 2031 | 0 | 0.0650 | 0 | 914 | 914 | (1,264) | 13,937 |
| 37 | 2032 | 0 | 0.0650 | 0 | 889 | 889 | (1,316) | 13,511 |
| 38 | 2033 | 0 | 0.0650 | 0 | 859 | 859 | (1,361) | 13,009 |
| 39 | 2034 | 0 | 0.0650 | 0 | 826 | 826 | (1,343) | 12,492 |
| 40 | 2035 | 0 | 0.0650 | 0 | 799 | 799 | (1,126) | 12,165 |
| 41 | 2036 | 0 | 0.0650 | 0 | 776 | 776 | (1,171) | 11,769 |
| 42 | 2037 | 0 | 0.0650 | 0 | 748 | 748 | (1,212) | 11,305 |
| 43 | 2038 | 0 | 0.0650 | 0 | 715 | 715 | (1,258) | 10,762 |
| 44 | 2039 | 0 | 0.0650 | 0 | 677 | 677 | (1,305) | 10,134 |
| 45 | 2040 | 0 | 0.0650 | 0 | 330 | 330 | (10,417) | 47 |
| | | 48,989 | | 48,989 | 216,821 | 265,810 | (300,498) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Salem Unit 2 Decommissioning Funding Analysis
($000)

| | | | Decommissioning Fund Details | | | | | |
|---|---|---|---|---|---|---|---|---|
| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
| 1 | Beginning Balance | | | | | | | 29,763 |
| 2 | 1997 | 1,850 | 0.0750 | 1,850 | 2,382 | 4,232 | 0 | 33,996 |
| 3 | 1998 | 1,850 | 0.0750 | 1,850 | 2,711 | 4,561 | 0 | 38,557 |
| 4 | 1999 | 2,509 | 0.0650 | 2,509 | 2,666 | 5,175 | 0 | 43,732 |
| 5 | 2000 | 2,509 | 0.0650 | 2,509 | 3,013 | 5,522 | 0 | 49,254 |
| 6 | 2001 | 2,509 | 0.0650 | 2,509 | 3,383 | 5,892 | 0 | 55,145 |
| 7 | 2002 | 2,509 | 0.0650 | 2,509 | 3,777 | 6,286 | 0 | 61,432 |
| 8 | 2003 | 2,509 | 0.0650 | 2,509 | 4,198 | 6,707 | 0 | 68,139 |
| 9 | 2004 | 2,509 | 0.0650 | 2,509 | 4,647 | 7,156 | 0 | 75,295 |
| 10 | 2005 | 2,509 | 0.0650 | 2,509 | 5,127 | 7,636 | 0 | 82,931 |
| 11 | 2006 | 2,509 | 0.0650 | 2,509 | 5,638 | 8,147 | 0 | 91,078 |
| 12 | 2007 | 2,509 | 0.0650 | 2,509 | 6,184 | 8,693 | 0 | 99,771 |
| 13 | 2008 | 2,509 | 0.0650 | 2,509 | 6,766 | 9,275 | 0 | 109,046 |
| 14 | 2009 | 2,509 | 0.0650 | 2,509 | 7,387 | 9,896 | 0 | 118,942 |
| 15 | 2010 | 2,509 | 0.0650 | 2,509 | 8,050 | 10,559 | 0 | 129,500 |
| 16 | 2011 | 2,509 | 0.0650 | 2,509 | 8,757 | 11,266 | 0 | 140,766 |
| 17 | 2012 | 2,509 | 0.0650 | 2,509 | 9,511 | 12,020 | 0 | 152,787 |
| 18 | 2013 | 2,509 | 0.0650 | 2,509 | 10,316 | 12,825 | 0 | 165,612 |
| 19 | 2014 | 2,509 | 0.0650 | 2,509 | 11,175 | 13,684 | 0 | 179,296 |
| 20 | 2015 | 2,509 | 0.0650 | 2,509 | 12,092 | 14,601 | 0 | 193,897 |
| 21 | 2016 | 2,509 | 0.0650 | 2,509 | 13,070 | 15,579 | 0 | 209,476 |
| 22 | 2017 | 2,509 | 0.0650 | 2,509 | 14,113 | 16,622 | 0 | 226,098 |
| 23 | 2018 | 2,509 | 0.0650 | 2,509 | 15,226 | 17,735 | 0 | 243,833 |
| 24 | 2019 | 2,509 | 0.0650 | 2,509 | 16,414 | 18,923 | 0 | 262,756 |
| 25 | 2020 | 0 | 0.0650 | 0 | 16,881 | 16,881 | (21,397) | 258,240 |
| 26 | 2021 | 0 | 0.0650 | 0 | 16,130 | 16,130 | (34,788) | 239,582 |
| 27 | 2022 | 0 | 0.0650 | 0 | 14,383 | 14,383 | (49,629) | 204,336 |
| 28 | 2023 | 0 | 0.0650 | 0 | 11,980 | 11,980 | (50,910) | 165,407 |
| 29 | 2024 | 0 | 0.0650 | 0 | 9,327 | 9,327 | (52,285) | 122,448 |
| 30 | 2025 | 0 | 0.0650 | 0 | 6,326 | 6,326 | (55,990) | 72,784 |
| 31 | 2026 | 0 | 0.0650 | 0 | 3,605 | 3,605 | (37,903) | 38,486 |
| 32 | 2027 | 0 | 0.0650 | 0 | 1,804 | 1,804 | (23,091) | 17,199 |
| 33 | 2028 | 0 | 0.0650 | 0 | 1,114 | 1,114 | (1,135) | 17,178 |
| 34 | 2029 | 0 | 0.0650 | 0 | 1,111 | 1,111 | (1,173) | 17,116 |
| 35 | 2030 | 0 | 0.0650 | 0 | 1,105 | 1,105 | (1,219) | 17,002 |
| 36 | 2031 | 0 | 0.0650 | 0 | 1,096 | 1,096 | (1,263) | 16,836 |
| 37 | 2032 | 0 | 0.0650 | 0 | 1,083 | 1,083 | (1,315) | 16,604 |
| 38 | 2033 | 0 | 0.0650 | 0 | 1,066 | 1,066 | (1,360) | 16,311 |
| 39 | 2034 | 0 | 0.0650 | 0 | 1,047 | 1,047 | (1,342) | 16,016 |
| 40 | 2035 | 0 | 0.0650 | 0 | 1,035 | 1,035 | (1,121) | 15,930 |
| 41 | 2036 | 0 | 0.0650 | 0 | 1,028 | 1,028 | (1,168) | 15,790 |
| 42 | 2037 | 0 | 0.0650 | 0 | 1,017 | 1,017 | (1,207) | 15,601 |
| 43 | 2038 | 0 | 0.0650 | 0 | 1,003 | 1,003 | (1,254) | 15,350 |
| 44 | 2039 | 0 | 0.0650 | 0 | 985 | 985 | (1,299) | 15,036 |
| 45 | 2040 | 0 | 0.0650 | 0 | 962 | 962 | (1,353) | 14,644 |
| 46 | 2041 | 0 | 0.0650 | 0 | 934 | 934 | (1,398) | 14,180 |
| 47 | 2042 | 0 | 0.0650 | 0 | 901 | 901 | (1,453) | 13,628 |
| 48 | 2043 | 0 | 0.0650 | 0 | 441 | 441 | (14,101) | (32) |
| | | 56,389 | | 56,389 | 272,968 | 329,357 | (359,153) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Peach Bottom Unit 1 Decommissioning Funding Analysis
($000)

| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
|---|---|---|---|---|---|---|---|---|
| | | | Decommissioning Fund Details | | | | | |
| 1 | Beginning Balance | | | | | | | 6,228 |
| 2 | 1997 | 740 | 0.0750 | 740 | 512 | 1,252 | 0 | 7,480 |
| 3 | 1998 | 740 | 0.0750 | 740 | 609 | 1,349 | 0 | 8,830 |
| 4 | 1999 | 2,992 | 0.0650 | 2,992 | 692 | 3,684 | 0 | 12,513 |
| 5 | 2000 | 2,992 | 0.0650 | 2,992 | 938 | 3,930 | 0 | 16,443 |
| 6 | 2001 | 2,992 | 0.0650 | 2,992 | 1,201 | 4,193 | 0 | 20,637 |
| 7 | 2002 | 2,992 | 0.0650 | 2,992 | 1,482 | 4,474 | 0 | 25,111 |
| 8 | 2003 | 2,992 | 0.0650 | 2,992 | 1,782 | 4,774 | 0 | 29,885 |
| 9 | 2004 | 2,992 | 0.0650 | 2,992 | 2,102 | 5,094 | 0 | 34,979 |
| 10 | 2005 | 2,992 | 0.0650 | 2,992 | 2,443 | 5,435 | 0 | 40,413 |
| 11 | 2006 | 2,992 | 0.0650 | 2,992 | 2,807 | 5,799 | 0 | 46,212 |
| 12 | 2007 | 2,992 | 0.0650 | 2,992 | 3,195 | 6,187 | 0 | 52,399 |
| 13 | 2008 | 2,992 | 0.0650 | 2,992 | 3,609 | 6,601 | 0 | 59,001 |
| 14 | 2009 | 2,992 | 0.0650 | 2,992 | 4,052 | 7,044 | 0 | 66,044 |
| 15 | 2010 | 2,992 | 0.0650 | 2,992 | 4,523 | 7,515 | 0 | 73,560 |
| 16 | 2011 | 2,992 | 0.0650 | 2,992 | 5,027 | 8,019 | 0 | 81,578 |
| 17 | 2012 | 2,992 | 0.0650 | 2,992 | 5,564 | 8,556 | 0 | 90,134 |
| 18 | 2013 | 0 | 0.0650 | 0 | 5,353 | 5,353 | (20,396) | 75,091 |
| 19 | 2014 | 0 | 0.0650 | 0 | 3,892 | 3,892 | (33,959) | 45,024 |
| 20 | 2015 | 0 | 0.0650 | 0 | 1,641 | 1,641 | (41,054) | 5,610 |
| 21 | 2016 | 0 | 0.0650 | 0 | 182 | 182 | (5,774) | 18 |
| | | 43,368 | | 43,368 | 51,606 | 94,974 | (101,184) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Peach Bottom Unit 2 Decommissioning Funding Analysis
($000)

| | | | Decommissioning Fund Details | | | | | |
|---|---|---|---|---|---|---|---|---|
| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
| 1 | Beginning Balance | | | | | | | 45,328 |
| 2 | 1997 | 2,773 | 0.0750 | 2,773 | 3,627 | 6,400 | 0 | 51,729 |
| 3 | 1998 | 2,773 | 0.0750 | 2,773 | 4,123 | 6,897 | 0 | 58,625 |
| 4 | 1999 | 2,588 | 0.0650 | 2,588 | 4,013 | 6,601 | 0 | 65,226 |
| 5 | 2000 | 2,588 | 0.0650 | 2,588 | 4,455 | 7,043 | 0 | 72,269 |
| 6 | 2001 | 2,588 | 0.0650 | 2,588 | 4,927 | 7,515 | 0 | 79,784 |
| 7 | 2002 | 2,588 | 0.0650 | 2,588 | 5,430 | 8,018 | 0 | 87,802 |
| 8 | 2003 | 2,588 | 0.0650 | 2,588 | 5,967 | 8,555 | 0 | 96,357 |
| 9 | 2004 | 2,588 | 0.0650 | 2,588 | 6,540 | 9,128 | 0 | 105,485 |
| 10 | 2005 | 2,588 | 0.0650 | 2,588 | 7,151 | 9,739 | 0 | 115,224 |
| 11 | 2006 | 2,588 | 0.0650 | 2,588 | 7,803 | 10,391 | 0 | 125,615 |
| 12 | 2007 | 2,588 | 0.0650 | 2,588 | 8,499 | 11,087 | 0 | 136,703 |
| 13 | 2008 | 2,588 | 0.0650 | 2,588 | 9,242 | 11,830 | 0 | 148,533 |
| 14 | 2009 | 2,588 | 0.0650 | 2,588 | 10,034 | 12,622 | 0 | 161,155 |
| 15 | 2010 | 2,588 | 0.0650 | 2,588 | 10,879 | 13,467 | 0 | 174,622 |
| 16 | 2011 | 2,588 | 0.0650 | 2,588 | 11,781 | 14,369 | 0 | 188,992 |
| 17 | 2012 | 2,588 | 0.0650 | 2,588 | 12,744 | 15,332 | 0 | 204,323 |
| 18 | 2013 | 0 | 0.0650 | 0 | 13,427 | 13,427 | (7,682) | 210,068 |
| 19 | 2014 | 0 | 0.0650 | 0 | 13,403 | 13,403 | (19,874) | 203,598 |
| 20 | 2015 | 0 | 0.0650 | 0 | 12,068 | 12,068 | (46,809) | 168,857 |
| 21 | 2016 | 0 | 0.0650 | 0 | 9,643 | 9,643 | (49,735) | 128,765 |
| 22 | 2017 | 0 | 0.0650 | 0 | 6,967 | 6,967 | (49,467) | 86,265 |
| 23 | 2018 | 0 | 0.0650 | 0 | 4,043 | 4,043 | (51,796) | 38,511 |
| 24 | 2019 | 0 | 0.0650 | 0 | 1,818 | 1,818 | (22,722) | 17,608 |
| 25 | 2020 | 0 | 0.0650 | 0 | 960 | 960 | (6,561) | 12,006 |
| 26 | 2021 | 0 | 0.0650 | 0 | 482 | 482 | (9,632) | 2,855 |
| 27 | 2022 | 0 | 0.0650 | 0 | 92 | 92 | (2,957) | (9) |
| | | 41,779 | | 41,779 | 180,119 | 221,898 | (267,235) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Peach Bottom Unit 3 Decommissioning Funding Analysis
($000)

| | | | Decommissioning Fund Details | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Line No | Year | Revenue Rqmt. [1] | Earning Rate [2] | Transfer To Fund [3] | Earnings [4] | ADIT Adjustment | Net Additions [5] | Decomm. Expend [6] | Balance [7] |
| 1 | Beginning Balance | | | | | | | | 45,366 |
| 2 | 1997 | 2,773 | 0.0750 | 2,773 | 3,630 | 0 | 6,402 | 0 | 51,768 |
| 3 | 1998 | 2,773 | 0.0750 | 2,773 | 4,127 | (17,775) | (10,876) | 0 | 40,892 |
| 4 | 1999 | 5,976 | 0.0650 | 5,976 | 2,939 | 0 | 8,915 | 0 | 49,807 |
| 5 | 2000 | 5,976 | 0.0650 | 5,976 | 3,536 | 0 | 9,512 | 0 | 59,319 |
| 6 | 2001 | 5,976 | 0.0650 | 5,976 | 4,173 | 0 | 10,149 | 0 | 69,468 |
| 7 | 2002 | 5,976 | 0.0650 | 5,976 | 4,852 | 0 | 10,828 | 0 | 80,296 |
| 8 | 2003 | 5,976 | 0.0650 | 5,976 | 5,578 | 0 | 11,554 | 0 | 91,850 |
| 9 | 2004 | 5,976 | 0.0650 | 5,976 | 6,351 | 0 | 12,327 | 0 | 104,177 |
| 10 | 2005 | 5,976 | 0.0650 | 5,976 | 7,177 | 0 | 13,153 | 0 | 117,330 |
| 11 | 2006 | 5,976 | 0.0650 | 5,976 | 8,058 | 0 | 14,034 | 0 | 131,364 |
| 12 | 2007 | 5,976 | 0.0650 | 5,976 | 8,998 | 0 | 14,974 | 0 | 146,338 |
| 13 | 2008 | 5,976 | 0.0650 | 5,976 | 10,001 | 0 | 15,977 | 0 | 162,315 |
| 14 | 2009 | 5,976 | 0.0650 | 5,976 | 11,071 | 0 | 17,047 | 0 | 179,362 |
| 15 | 2010 | 5,976 | 0.0650 | 5,976 | 12,212 | 0 | 18,188 | 0 | 197,550 |
| 16 | 2011 | 5,976 | 0.0650 | 5,976 | 13,430 | 0 | 19,406 | 0 | 216,956 |
| 17 | 2012 | 5,976 | 0.0650 | 5,976 | 14,730 | 0 | 20,706 | 0 | 237,662 |
| 18 | 2013 | 5,976 | 0.0650 | 5,976 | 16,117 | 0 | 22,093 | 0 | 259,755 |
| 19 | 2014 | 0 | 0.0650 | 0 | 17,097 | 389 | 17,485 | (8,951) | 268,289 |
| 20 | 2015 | 0 | 0.0650 | 0 | 17,349 | 802 | 18,152 | (18,468) | 267,973 |
| 21 | 2016 | 0 | 0.0650 | 0 | 16,113 | 2,379 | 18,491 | (54,765) | 231,699 |
| 22 | 2017 | 0 | 0.0650 | 0 | 13,566 | 2,531 | 16,097 | (58,262) | 189,534 |
| 23 | 2018 | 0 | 0.0650 | 0 | 10,680 | 2,612 | 13,292 | (60,142) | 142,683 |
| 24 | 2019 | 0 | 0.0650 | 0 | 7,440 | 2,744 | 10,184 | (63,184) | 89,683 |
| 25 | 2020 | 0 | 0.0650 | 0 | 4,788 | 1,580 | 6,368 | (36,371) | 59,681 |
| 26 | 2021 | 0 | 0.0650 | 0 | 3,206 | 1,026 | 4,232 | (23,623) | 40,289 |
| 27 | 2022 | 0 | 0.0650 | 0 | 2,314 | 498 | 2,812 | (11,471) | 31,631 |
| 28 | 2023 | 0 | 0.0650 | 0 | 2,062 | 73 | 2,135 | (1,690) | 32,076 |
| 29 | 2024 | 0 | 0.0650 | 0 | 2,089 | 76 | 2,166 | (1,758) | 32,484 |
| 30 | 2025 | 0 | 0.0650 | 0 | 2,115 | 79 | 2,194 | (1,819) | 32,859 |
| 31 | 2026 | 0 | 0.0650 | 0 | 2,137 | 82 | 2,219 | (1,887) | 33,191 |
| 32 | 2027 | 0 | 0.0650 | 0 | 2,157 | 85 | 2,242 | (1,958) | 33,476 |
| 33 | 2028 | 0 | 0.0650 | 0 | 2,174 | 88 | 2,262 | (2,037) | 33,700 |
| 34 | 2029 | 0 | 0.0650 | 0 | 2,186 | 92 | 2,278 | (2,108) | 33,871 |
| 35 | 2030 | 0 | 0.0650 | 0 | 2,195 | 95 | 2,290 | (2,187) | 33,974 |
| 36 | 2031 | 0 | 0.0650 | 0 | 2,199 | 99 | 2,298 | (2,269) | 34,002 |
| 37 | 2032 | 0 | 0.0650 | 0 | 2,198 | 103 | 2,301 | (2,361) | 33,942 |
| 38 | 2033 | 0 | 0.0650 | 0 | 2,191 | 106 | 2,297 | (2,443) | 33,797 |
| 39 | 2034 | 0 | 0.0650 | 0 | 2,179 | 110 | 2,289 | (2,535) | 33,551 |
| 40 | 2035 | 0 | 0.0650 | 0 | 2,159 | 114 | 2,273 | (2,630) | 33,194 |
| 41 | 2036 | 0 | 0.0650 | 0 | 2,131 | 119 | 2,250 | (2,736) | 32,708 |
| 42 | 2037 | 0 | 0.0650 | 0 | 2,096 | 123 | 2,219 | (2,831) | 32,096 |
| 43 | 2038 | 0 | 0.0650 | 0 | 2,051 | 128 | 2,179 | (2,937) | 31,337 |
| 44 | 2039 | 0 | 0.0650 | 0 | 1,997 | 132 | 2,129 | (3,048) | 30,419 |
| 45 | 2040 | 0 | 0.0650 | 0 | 1,931 | 138 | 2,069 | (3,171) | 29,317 |
| 46 | 2041 | 0 | 0.0650 | 0 | 905 | 1,372 | 2,278 | (31,597) | (2) |
| | | 95,185 | | 95,185 | 268,685 | (0) | 363,870 | (409,239) | |

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

PECO ENERGY COMPANY

Net Present Value of Fossil Decommissioning Costs
As of January 1, 1999
($000)

| Year | Eddystone 1&2 | Eddystone 3&4 | Cromby 1 | Cromby 2 | Schuykill 1 | Delaware 7&8 | Keystone 1 | Keystone 2 | Conemaugh 1 | Conemaugh 2 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1999 | $0 | $0 | $0 | $0 | $4,977 | $8,826 | $0 | $0 | $0 | $0 | $13,802 |
| 2000 | 0 | 0 | 0 | 0 | 2,857 | 1,623 | 0 | 0 | 0 | 0 | 4,480 |
| 2001 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2002 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2003 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2004 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2005 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2006 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2007 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 0 | 0 | 2,340 | 4,157 | 0 | 0 | 0 | 0 | 0 | 0 | 6,497 |
| 2011 | 0 | 0 | 1,672 | 2,504 | 0 | 0 | 0 | 0 | 0 | 0 | 4,175 |
| 2012 | 0 | 0 | 734 | 950 | 0 | 0 | 0 | 0 | 0 | 0 | 1,683 |
| 2013 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2015 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2018 | 0 | 0 | 0 | 0 | 0 | 0 | 452 | 1,183 | 0 | 0 | 1,635 |
| 2019 | 0 | 0 | 0 | 0 | 0 | 0 | 873 | 1,040 | 0 | 0 | 1,913 |
| 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 842 | 1,004 | 0 | 0 | 1,846 |
| 2021 | 0 | 0 | 0 | 0 | 0 | 0 | 813 | 968 | 417 | 1,150 | 3,348 |
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | 154 | 309 | 804 | 923 | 2,191 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | 106 | 220 | 776 | 890 | 1,993 |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 749 | 859 | 1,608 |
| 2025 | 5,829 | 4,446 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 98 | 10,385 |
| 2026 | 3,349 | 2,713 | 0 | 0 | 0 | 0 | 0 | 0 | 94 | 127 | 6,283 |
| Total | $9,177 | $7,158 | $4,745 | $7,610 | $7,833 | $10,449 | $3,240 | $4,725 | $2,853 | $4,048 | $61,839 |

Note: Based on discount rate of 7.53%.

PECO ENERGY COMPANY

Schedule of Fossil Decommissioning Costs by Year
($000)

| Year | Eddystone 1&2 | Eddystone 3&4 | Cromby 1 | Cromby 2 | Schuykill 1 | Delaware 7&8 | Keystone 1 | Keystone 2 | Conemaugh 1 | Conemaugh 2 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Current Cost | $25,842 | $20,167 | $7,814 | $12,491 | $8,173 | $10,798 | $7,513 | $10,904 | $7,335 | $10,320 | $121,356 |
| 1997 | | | | | | | | | | | |
| 1998 | | | | | | | | | | | 0 |
| 1999 | | | | | $5,351 | $9,490 | | | | | 14,842 |
| 2000 | | | | | $3,303 | $1,877 | | | | | 5,180 |
| 2001 | | | | | | | | | | | 0 |
| 2002 | | | | | | | | | | | 0 |
| 2003 | | | | | | | | | | | 0 |
| 2004 | | | | | | | | | | | 0 |
| 2005 | | | | | | | | | | | 0 |
| 2006 | | | | | | | | | | | 0 |
| 2007 | | | | | | | | | | | 0 |
| 2008 | | | | | | | | | | | 0 |
| 2009 | | | | | | | | | | | 0 |
| 2010 | | | $5,592 | $9,933 | | | | | | | 15,525 |
| 2011 | | | $4,295 | $6,434 | | | | | | | 10,729 |
| 2012 | | | $2,027 | $2,624 | | | | | | | 4,651 |
| 2013 | | | | | | | | | | | 0 |
| 2014 | | | | | | | | | | | 0 |
| 2015 | | | | | | | | | | | 0 |
| 2016 | | | | | | | | | | | 0 |
| 2017 | | | | | | | | | | | 0 |
| 2018 | | | | | | | $1,930 | $5,054 | | | 6,984 |
| 2019 | | | | | | | $4,010 | $4,777 | | | 8,788 |
| 2020 | | | | | | | $4,161 | $4,957 | | | 9,118 |
| 2021 | | | | | | | $4,317 | $5,143 | $2,213 | $6,108 | 17,782 |
| 2022 | | | | | | | $881 | $1,767 | $4,593 | $5,270 | 12,512 |
| 2023 | | | | | | | $650 | $1,352 | $4,766 | $5,468 | 12,236 |
| 2024 | | | | | | | | | $4,945 | $5,674 | 10,618 |
| 2025 | $41,389 | $31,567 | | | | | | | $91 | $696 | 73,742 |
| 2026 | $25,568 | $20,713 | | | | | | | $721 | $969 | 47,971 |
| Total | $66,957 | $52,280 | $11,914 | $18,991 | $8,654 | $11,367 | $15,950 | $23,050 | $17,330 | $24,185 | $250,679 |

**ATTACHMENT A**

**TO**

**DIRECT TESTIMONY OF**
**THOMAS S. CATLIN**

THOMAS S. CATLIN

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

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

Education:

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

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

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

Previous Employment:

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

Professional Work:

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

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

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

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

Publications:

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

Before State Commissions:

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

<u>Prior Expert Testimony</u>

<u>of Thomas S. Catlin</u>

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

Prior Expert Testimony

of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

Prior Expert Testimony

of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

Prior Expert Testimony

of Thomas S. Catlin

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

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

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

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

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

# Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

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

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

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

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

# Prior Expert Testimony

## of Thomas S. Catlin

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

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

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP97-197-000), January 1996. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

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

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

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

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

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

## Prior Expert Testimony

## of Thomas S. Catlin

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

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

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

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

R-00973953
OCA STATEMENT NO. 4
Phila. 10/14, 15, 14/97
E. Holbert

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| APPLICATION OF PECO ENERGY FOR | : | |
| APPROVAL OF ITS RESTRUCTURING | : | Docket No. R-00973953 |
| PLAN UNDER SECTION 2806 OF THE | : | |
| PUBLIC UTILITY CODE | : | |



DIRECT TESTIMONY

OF

LEE SMITH



On Behalf of:

OFFICE OF CONSUMER ADVOCATE



JUNE 1997

**TESTIMONY OF LEE SMITH FOR**

**PENNSYLVANIA OFFICE OF THE CONSUMER ADVOCATE**

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. WHAT IS YOUR OCCUPATIONAL EXPERIENCE?

A. I am Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 13 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level.

Q. ARE THERE ANY ATTACHMENTS TO THIS TESTIMONY?

A. Yes. A summary of my qualifications and experience is attached at the end of my testimony as Exhibit LS-1.

**Unbundled Rate Design**

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on rate design aspects of the restructuring proceeding, including the functionalization of costs, the allocation of costs to rate classes, the resulting unbundling of rates, and the design of an appropriate CTC.

Q. HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE AND FUNCTIONAL UNBUNDLING INTO THE PRODUCTION, TRANSMISSION AND DISTRIBUTION COMPONENTS?

A. Yes. In general, I agree with the Company's approach to cost allocation in order to functionally unbundle the current rates. The Company's witness, Mr. Robert A. Clemmer, has sponsored a 1996 proforma cost of service study using the class rates of return and allocators for the retail classes that were the basis for the current rate schedules. The Act specifies that stranded costs be allocated "in a manner that does not shift inter-class or intra-class costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceedings" (Act, section 2808(a)). The Company's approach is generally responsive to the mandate of the Act for the retail rate classes.

Q. DOES THIS SIMPLY MEAN USING THE SAME ALLOCATOR THAT WAS USED FOR THE COST IN THE LAST RATE CASE?

A. No, it also requires a reflection of the class rates of return that were allowed in the last case. For instance, a class might have a generation capacity allocator of 30%, but an allowed rate of return that was only 90% of the system average rate of return. The revenue requirement associated with plant items are not the net book value of the plant but the return on this amount. This class would then be allocated 30% of generation plant net book value, but since its rate of return was less than the average its final cost responsibility for generation plant would only be 90% times 30%, or 27%. Thus maintaining the same cost responsibility for rate base costs means using the same allocator adjusted for the class rate of return. The Company for the most part has followed this approach.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S FUNCTIONAL UNBUNDLING?

A. Yes, I have concerns in three major areas: the treatment of jurisdictional sales; the functional unbundling of administrative and general expenses and general plant into production, transmission and distribution; and the Company's method of "deriving" the avoidable rate component after fixing distribution, transmission and a competitive transition charge. I also have some comments on the reconciliation of stranded cost and the treatment of universal service program costs.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE COMPANY'S TREATMENT OF JURISDICTIONAL WHOLESALE SALES.

A. The stranded costs were created as the Company acquired resources to serve its entire load, including its wholesale load. It cannot be allowed to shift cost responsibility onto retail customers only. The Act specifies that stranded cost responsibility may not be shifted. In the previous cost of service study, the "Other Utilities" class was allocated its appropriate share of generation costs, and earned a rate of return of 12%. In the current presentation, "other utilities" are not shown as a separate rate class. These sales are included in the category labeled "COPCO and Class A & B Revenues", to which the Company allocates no stranded costs. There has been a change in treatment of sales to the former Conowingo Power Company, which PECO has sold to Delmarva. The Company includes this with Class A and B and allocates no stranded cost to the class. These customers had been included in the Company's capacity planning. They should bear a share of responsibility for stranded costs. It is not consistent with the intent of the Act to relabel classes or to establish new relationships with some customers and then fail to assign any stranded costs to them.

Q. IF THE COMPANY HAS NOT ALLOCATED COSTS TO THESE CLASSES, HOW HAVE THEY BEEN TREATED IN THE COST OF SERVICE STUDY?

A. The Company has applied the revenue crediting approach. No costs are allocated to this class, but all class revenues are utilized as a credit that reduces the revenue requirements of the retail classes. These revenues may be more or less than the allocated costs of serving these wholesale customers may have been. This approach does not demonstrate whether firm wholesale sales are or are not paying an appropriate amount of stranded costs. This may be appropriate treatment for very transient sales; these should not be made unless revenues are greater than short-run marginal costs, but economy energy has been priced by the market. However, sales that have created an obligation for the Company to provide firm capacity should bear some of the responsibility for stranded costs.

Q. WHAT DO YOU RECOMMEND AS A METHOD OF ALLOCATING STRANDED COSTS TO FIRM WHOLESALE CUSTOMERS?

A. The revenues credited to retail customers from these wholesale customers should be equal to the cost of generation; that is, the market price plus the CTC. Once we have defined the full stranded cost amount, it is allocated to rate classes. We have developed an allocator for the wholesale class based on the allocation in the previous case. Since the only load information presented about this class in this case is the kWh sales, we have assumed the same relationship between the class 4CP (the generation capacity allocator) and kWh sales as existed in the previous case. The wholesale COPCO class should be allocated about 4% of stranded costs. The 1996 revenues received from these customers appear adequate to recover the market cost of generation plus the CTC. The current rate thus is paying the appropriate share of stranded cost. However, this must be recognized in future computation of the CTC and reconciliation. This will be discussed later in the reconciliation section. Exhibit LS-2 shows the computation of the wholesale stranded cost allocation.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE COMPANY'S TREATMENT OF ITS ADMINISTRATIVE AND GENERAL EXPENSES.

A. The Company has allocated a number of administrative and general ("A&G") expenses and general plant only to the transmission and distribution functions. A substantial percentage of these costs should be allocated to the production function as well. Costs in these accounts are not easily identifiable with particular operating functions. They include salaries and office supplies for personnel in administrative functions, such as human resources, legal, or accounting. These activities contribute to the generation function as well as distribution and transmission. Generation planners and marketers make use of these administrative functions and expenses. An appropriate functionalization of these accounts is one based on the total labor costs in each utility function.

For example, the payroll department of a utility is not directly involved in any of the major functional areas, but provides support services for these functions; the more personnel in a department, the larger the portion of the payroll department that would be needed. An appropriate functionalization of the payroll department's costs is based on the directly identified labor costs of the distribution, transmission and generation functions.

Q. HOW DID THE COMPANY FUNCTIONALIZE THESE EXPENSES?

A. The Company did use a labor allocator in functionalizing A&G expenses, but it was not the correct labor allocator because it excluded labor associated with the production function. In other words, to use our previous example, the payroll department would be functionalized only to T&D.

Q. WHY DID THE COMPANY ALLOCATE ALL OF THESE COSTS TO T&D?

A. The Company's rationale for functionalizing these costs to T&D was that they "would continue unchanged, and would remain with the local distribution Company after functional unbundling occurred" (response to Enron-I-36). It is irrelevant whether these costs remain the same. For instance, if generation labor benefits were projected to remain the same from 1996 to 1999, that would not be a reason to assign them to the T&D function. The same is true of other administrative and general expenses. Even if the Company does need the same number of people in the payroll department and other A&G accounts, their cost should be allocated to the functions that they support. It is simply incorrect to allocate these dollars entirely to T&D.

Unbundling costs should produce results that should look like what functional costs would be if PECO were to separate itself into functionally separate divisions. Clearly the generation division would require administrative and general services.

Q. IS THERE A MAJOR PROBLEM WITH THE COMPANY'S APPROACH, SINCE CUSTOMERS WILL PAY THE SAME TOTAL AMOUNT IN ANY CASE?

A. The Company's approach would result in distribution customers paying for services that were utilized to assist in production and the marketing of production services. To ignore the fact that some of these costs are production-related understates the Company's cost of generation. The commission should ensure that these costs are properly identified, so that competitive suppliers are not disadvantaged in having to compete with utility generation exclusive of overhead expenses.

Q. DID THE COMPANY ALLOCATE ANY ADMINISTRATIVE AND GENERAL COSTS TO THE GENERATION FUNCTION?

A. Yes. It correctly allocated property insurance on plant. It also allocated some benefits and pensions to the generation function. However, this allocation is also flawed, because before determining what percentage of labor was in the generation function, it first included all administrative and general labor in the T&D function. In other words, all A&G labor was assigned to T&D before the labor allocator was developed. The correct allocation would reflect only directly functionalized labor. The pensions and benefits associated with A&G labor would then be allocated in the same manner as other A&G expenses.

Q. HOW HAVE YOU CORRECTED THE COST OF SERVICE STUDY FOR ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSES?

A. I allocated all administrative and general expense, except property insurance (account 924), by a labor allocator that reflected the amount of labor that is directly allocated to each function. For instance, in 1996, 66% of all directly functionalized labor was in the generation function, so 66% of administrative and general expenses was functionalized as to the generation category. This reallocation resulted in a reduction to T&D expense of $150 million.

The workpapers for my calculations are in Exhibit LS-3. Page 1 of this Exhibit shows the Company's allocation of A&G and general plant from the Company's Exhibit RAC-1, and the alternative allocation that I am proposing. Page 2 of Exhibit LS-3 shows the derivation of the Company's labor allocator at the top and a corrected allocation based on direct labor costs at the bottom. After properly assigning A&G and general costs to functions, I allocated these costs to the rate classes as in the Company's original cost of service study.

Q. ARE THERE OTHER IMPLICATIONS OF THESE CHANGES IN ALLOCATION?

A. Yes. This shift of dollars results in a decrease in T&D costs and an increase in 1996 generation costs. The T&D rate decreases and the resulting generation rate increases. The Company's functionalization has understated the cost of getting generation to customers by the amount of administrative and general costs (except those associated with pensions and benefits (adjusted for overaccrual) and property insurance) that will be required to market, aggregate load, reconcile load and supply, deal with PJM, write contracts, and all the activities that will be required to get power to customers. These costs are all part of the avoidable cost of energy. Either PECO or alternative suppliers will provide the services that these costs represent to customers purchasing generation. I have treated these dollars as an amount that must be added to the retail spot cost of power.

Q. PLEASE DESCRIBE THE ADMINISTRATIVE AND GENERAL EXPENSES THAT YOU HAVE USED IN THE COMPUTATION OF THIS ADDER TO THE SPOT PRICE.

A. I began this computation by modifying the functionalization of A&G for all accounts except 924 and 926 by applying the labor allocator so that generation bears its share. From this I subtracted regulatory expense, since the generation function will no longer be regulated. Next I reduced this amount by 10% to reflect mitigation of expenses. This reduction is consistent with the Company's assumptions about O&M expense. This resulted in on-going A&G expense of $117 million in 1999 which must be collected from the avoidable energy price. This amount is escalated each year.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE COMPANY'S UNBUNDLED AVOIDABLE GENERATION RATE COMPONENT.

A. The Company has proposed to unbundle its current rate level into four components: distribution, transmission, competitive transition, and generation. It would accomplish this by fixing the revenue requirement associated with the distribution and transmission components, and by also developing fixed competitive transition charges ("CTC") for the entire transition period. The CTC is set on a levelized basis so that it will return the full dollar amount of the Company's stranded cost, plus a return on the unamortized balance during the seven years. The overall rates are fixed by the rate cap provisions in the Act, so that the avoidable component, the CTC (plus ITC), and the T&D rates cannot exceed this level. The Company defined the avoidable generation component as the residual, that is, the difference between the current rate and the sum of the CTC and the T&D rate.

The Company's proposed generation component, which is fixed for the transition period, does not bear any relationship to the cost of providing power to the retail customer. Leaving aside the administrative and general cost described above, the initial year's generation component is not even equal to the market price of power, and since the market price is projected to increase every year, the market price will grow increasingly larger than the avoidable component.

Q. WHAT ARE THE IMPLICATIONS OF THE MARKET PRICE BEING HIGHER THAN THE AVOIDABLE COMPONENT OF THE RATE?

A. It will make it impossible for other suppliers to compete for this load. Since PECO will be providing a standard offer price that will be below, and in some cases, significantly below, the market price, customers will see no reason to switch suppliers to competitors that are charging the market price.

Q. WHAT IS THE AVOIDABLE PRICE OF POWER TO THE RETAIL CUSTOMER?

A. This price begins with the market price of power; it is a wholesale price. The retail price must reflect the energy that is lost in the distribution process and will also be higher than the all-hours market price because of the class load shape. We have estimated the retail cost of power, based on the response to OCA II-7, as reflecting line losses, gross receipt taxes, and differential class load shapes, applied to Mr. Smith's estimate of wholesale market price. The residential average market price in 1999 will be 2.99 cents per kwh. It also must include a component for the transactions costs; the costs of providing generation to the customer, such as load aggregating, marketing, contracting, etc. The amount of additional cost that will be incurred to provide power to the customer, based on the $117 million described above, will be 5.6 mills per kwh for residential customers, for a total weighted average avoidable generation cost of 3.55 cents to the residential customer in 1999.

Q. WHAT IS THE FUNDAMENTAL DIFFERENCE BETWEEN WHAT THE COMPANY HAS PROPOSED AND WHAT YOU ARE PROPOSING?

A. The fundamental difference is that the Company's proposal will not allow customers real choice of supplier, and will severely impede the development of retail competition for generation services. Since customers will be comparing the avoidable generation rate component to offers from alternative suppliers, the Commission should take steps to ensure that this is a meaningful choice. If the avoidable generation component is less than the market price of power, then customers will have no real alternatives, and this would be inconsistent with customer choice. It would be "business as usual" for the Company and have the effect of stifling any true competition. The Company would be able to collect the full cost of generation through the competitive transition charges, but non-utility suppliers would have to absorb their own losses if they wished to compete with the unrealistically low generation prices offered by PECO.

In the Company's pilot program the Company claimed that the avoidable component was set at the wholesale market price and the CTC was the residual. While it appears that this wholesale market price understated the retail market price and further understated the avoidable cost, the general approach is more correct than what the Company has presented in this case.

Q. HAVE YOU CORRECTED THESE DEFICIENCIES IN THE COMPANY'S FILING?

A. Yes. In Exhibit LS-5, I have shown what unbundled rates should be over time. The estimate of the avoidable price of power reflects an increase from the market prices produced by Mr. Douglas Smith reflecting line losses, the gross receipts tax, and the administrative and general piece. The resulting average rates are shown in this Exhibit. These average rates consist of a T&D component that is lower than that proposed by the Company; a generation market price component; and the CTC component based on Mr. La Capra's recommendation. Overall, this results in a 23% decrease to the current rates in 1999. As the generation rate increases to reflect future market prices the overall rate would rise closer to current levels by 2005. In 2006 the rate will decrease by approximately 11% from the 2005 level with the elimination of the CTC.

Q. HAVE YOU DEVELOPED RESIDENTIAL UNBUNDLED RATES FROM THE CURRENT RATES, WITH THE CHANGES DESCRIBED ABOVE?

A. Yes. The T&D rates, the generation rates, and the CTC rate for rate R, the major residential class, are shown for the year 1999 on Exhibit LS-6. These rates reflect a 21% decrease from the current rate level.

Q. THE CTC MAY NOT BE LARGER THAN THE RESIDUAL THAT IS LEFT UNDER THE RATE CAP AFTER SUBTRACTING THE MARKET COST OF POWER AND THE T&D RATE. HAVE YOU CALCULATED THE ACTUAL ANNUAL CTCS?

A. Yes. Based on the total stranded cost amount as determined by the testimony of Mr. La Capra, (without any adjustment for securitization), I know the total retail amount to be collected without a return. Since the market cost of power increases over time, the amount left under the rate cap decreases every year. I began by simply dividing the CTC by the expected total of sales over the seven year recovery period. I have assumed a sales growth of 1.26% annually. This is the rate of growth projected by the Company in the 1997 Annual Resource Planning Report. (Environmentalist II-112(a)) This is similar to the Company's approach, except the Company included a return on the unamortized balances and assumed no sales growth. As discussed in the testimony of Mr. La Capra, I have not included such a return. The combination of the levelized CTC and the increasing market cost results in an increasing total generation price over the seven years, but does fit under the generation rate cap for the entire period. This approach results in a significant initial rate decrease, and the total rate would then increase as the market price went up. As noted above, the rates would be reduced again significantly in 2006 with the elimination of the CTC.

Q. THE COMPANY PROPOSES TO RECONCILE ITS STRANDED COST BY ADJUSTING THE DATE AT WHICH IT CEASES TO COLLECT THE CTC RATHER THAN THROUGH ADJUSTING THE CTC ANNUALLY. DO YOU AGREE WITH THIS APPROACH?

A. Yes. It will be less confusing to customers to adjust the timing rather than the CTC factor. Obviously, the reconciliation must be to the approved retail stranded cost amount. However, if the CTC collection period is extended beyond December 31, 1997, so should the rate cap be extended. That is, the Commission must condition any extension of the CTC collection on the Company's agreement to extend the generation rate cap by an equivalent period.

Q. ARE THERE ANY OTHER ISSUES OF CONCERN WITH REGARD TO THE RECONCILIATION OF STRANDED COST?

A. Yes. As noted earlier, accounting for collection of the CTC should reflect a recovery of 4% from the wholesale class. Also, I am concerned that the reconciliation process could conceivably shift some cost responsibility onto certain customer classes. This would be the case, for instance, if in spite of the Company's attempt to identify sales lost due to additional self-generation, the industrial load paying the CTC decreased. It could also result from changes in load shape in the demand-metered classes. The Company might also in the future award economic development discounts to its largest customers in order to retain load. In all of these instances, stranded cost collection could decrease. If the reconciliation is done on a class-specific basis, this problem would be avoided. In other words, the 1997 class allocation of CTC costs would be applied in the reconciliation process. This could result in some classes finishing CTC collection before others.

Q. ARE THERE ANY OTHER RATE DESIGN ISSUES WHICH YOU WOULD LIKE TO DISCUSS?

A. Yes. First are issues related to low income programs. Second is the treatment of the various commercial and industrial rate "riders."

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S TREATMENT OF THE LOW INCOME PROGRAMS?

A. Consistent with the testimony of the OCA witness Brockway, I have allocated these costs to all customer classes. In addition, the actual low income rate discount, should be applied only to the non-avoidable portions of the rate at this time. The avoidable generation cost should not be discounted. As discussed earlier, utilizing an avoidable cost that is less than the retail market cost of power does not allow real choice of supplier. Applying the discount only to the non-avoidable portion of the rate results in a higher discount percentage to the remaining portions.

Q. THE COMPANY HAS A NUMBER OF SPECIAL RIDERS TO RATES WHICH IT PROPOSES TO TREAT IN A DIFFERENT MANNER. PLEASE DISCUSS.

A. The Company has a number of riders to which it plans to limit availability to customers whose sole source of supply is PECO. In some cases it also argues that these rates should not be unbundled. For rates where PECO offers discounts to generation price for interruption, the discount relates to the cost of generation and clearly would not be applicable were the customer to take service from another supplier. This applies to the Auxiliary Service and the

Curtailment HT Rider. The Company also proposes to limit the application of the Emergency Energy Conservation Rider and the Employment and Economic Recovery Rider to customers who purchase energy from PECO. Again, this is an appropriate restriction.

I do not, however, agree that these rates should not be unbundled. They should be unbundled not for the purpose of allowing customers choice of generation supplier, but for the purpose of collecting and accounting for stranded costs. Since the generation component on these rates is less than the fully allocated cost, these rates include less than the average amount of stranded cost for customers on the other commercial and industrial rates. However, they should continue to provide the amount of contribution to stranded costs that they are currently providing, and this contribution should be identifiable and should be accounted for in stranded cost collection.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

**LEE SMITH**

LA CAPRA ASSOCIATES
Senior Economist

EDUCATION

**TUFTS UNIVERSITY**, all but dissertation for Ph.D., Economics
**BOSTON COLLEGE,** Study of Statistics
**BROWN UNIVERSITY,** Bachelor of Arts with Honors, International Relations and Economics

Experience

| | |
|---|---|
| 1984- | LA CAPRA ASSOCIATES<br>Senior Economist Ms. Smith's work has encompassed all costing issues, forecasting, rate design, demand and supply planning regarding electric and gas utilities. Ms. Smith has extensive experience in testifying and negotiating. |
| 1982-84 | Department of Public Utilities; Director of Rates and Research |
| 1981-82 | Department of Public Utilities; Economist, Long-Run Planning |
| 1978-79 | REGIS COLLEGE, Lecturer in Economics |
| 1974-77 | MERRIMACK COLLEGE, Lecturer in Economics |
| 1973-74 | UNIVERSITY OF MARYLAND, Faculty Research Associate |
| 1972-73 | TUFTS UNIVERSITY, Lecturer in Economics |
| 1967 | FEDERAL RESERVE BANK of Boston, Administrative Assistant, Research Department |
| 1965-66 | FEDERAL RESERVE BANK, Research Assistant, Banking and Regional Policy |

Publications:

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

Papers:

"Development and Implementation of Restructuring in New England", Institute of Public Utilities at Michigan State University Williamsburg Conference, December 1995

"Planning for Gas and Electric Reliability", NARUC Biennial Regulatory Information Conference, Vol. II, 1994

"The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland", JOHN HOPKINS PRESS

Honors:

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Brown University International Relations Prize, 1965

Description of Selected Projects

1996 New Hampshire Public Utilities Commission

Assisted Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.

1996 Blackstone Gas Company

Prepared rate case and negotiated settlement; negotiated special contracts for sales and transportation of gas.

1996 Massachusetts Division of Energy Resources

Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

1996 CMEEC

Developed methodologicalbasis for rate unbundling for the five Connecticut municipal utilities that are members of CMEEC.

1995 Black Hills Power and Light Company (South Dakota)

Advised Company on development of ancillary services and open access transmission rates.

1995 Pennsylvania Office of the Consumer Advocate

Assisted with preparation of comments on restructuring issues

1995 Maine Office of the Public Advocate

Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

| | |
|---|---|
| 1995 | Massachusetts Division of Energy Resources |
| | Assisted DOER in all aspects of electric industry restructuring, from rate unbundling to planning and developing revised market structure for the New England Power Pool. |
| 1995 | Littleton Water and Light Department (N.H.) |
| | Developed retail wheeling rate; advised on retail wheeling policy issues |
| 1995 | Kansas Citizens' Utility Ratepayers Board |
| | Prepared testimony on cost allocation and rate design for local gas distribution utility. Assisted in settlement negotiations. |
| 1995 | Boston Edison Company |
| | Presented rate design workshop for Company personnel to assist in preparing for restructuring. |
| 1995 | World Bank |
| | Developing conditions under which State of Orissa, which is privatizing its electric distribution system, should consider revaluation; assisting with other restructuring issues. |
| 1994 | Division of Energy Resources |
| | Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs. |
| 1994 | Black Hills Power and Light Company (South Dakota) |
| | Advised Company on rate treatment and phase-in of major new generating unit, development of wholesale transmission rate, and response to retail wheeling. |
| 1994 | New Hampshire Office of the Consumer Advocate |

Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

1994 Massachusetts Municipal Wholesale Electric Company

Testified for MMWEC on appropriate allocation of gas transition costs; assisted MMWEC in formulating response to generic docket on interruptible gas transportation; prepared comments.

1994 Town of Fort Fairfield

Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

1994 Blackstone Gas Company

Formulated plan for settlement of long-term debt with Tennessee Gas Pipeline Company; gained Massachusetts DPU approval for long-term debt financing.

1993 North Attleborough Gas Company

Revised long-run econometric forecast of load, assisted Company in preparation of supply/demand forecast for DPU.

1994 Constellation Energy

Projected market price of power, advised developer on potential market.

1994 Stow Electric Energy Study Committee

Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

1993 Massachusetts Department of Energy Resources;

Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

1993 Eastern Energy Associates

Directed analysis and computation of avoided costs of a major electric utility.

1993 Blackstone Gas Company

Issued RFP, planned gas supply, negotiated supply contracts for small gas LDC.

1993 Maine Public Utility Commission Staff

Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.

1993 Essex County Gas

Advised Company on long-run planning issues; developed innovative approach to reliability planning standards; directed full Demand and Supply Forecast which has been submitted to the Massachusetts Energy Facilities Siting Board.

1993 North Attleborough Gas Company

Directed development of long-run econometric forecast of load by type of customer.

1993 Office of the People's Counsel, Washington D.C.

Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program, including $10 million in expenses of conservation programs.

1993 Plattsburgh Municipal Lighting Department

Advised utility on selection of least-cost power contracts.

1993 Wakefield Municipal Light Department

Presented testimony on gas distribution systems, transportation pricing issues in Boston Gas Company rate case.

1993 Nantucket Electric Company

Directed development of long-run end-use load forecast for tourism-based economy.

1992 Massachusetts Municipal Wholesale Electric Company

Analysis of and testimony on economic inefficiencies created by Bay State pricing of interruptible gas to Stony Brook generating unit.

1992 Woodsville Water and Light Department

Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.

1992 Stow Electric Energy Study Committee

Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.

1992 Boston Edison Electric Company

Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.

1992 Plattsburgh Municipal Light Department

Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.

1992 Colonial Gas Company

Directed analysis of company's new pipeline transportation contract with ANE (Iroquois); tested cost-effectiveness, analyzed non-pricing contract attributes.

1992 North Attleborough Gas Company

Presented Company rate filing, including reconciliation of actual year experience with predictions of previous settlement.

1992 Altresco

Advised on siting, fuel costs, and bidding of potential new intermediate power project.

1992 Middleton Electric Light Department

Renegotiation of contract for transmission of all power to the utility.

1992 Nantucket Electric Company

Directed revision of load research sampling (determining appropriate sample size and selection)

1991 Colonial Gas Company

Assisted in development of Conservation and Load Management Plan, including development of avoided gas supply and distribution costs.

1991 Essex County Gas

Prepared rate designs, testified in rate case on Company's marginal costs and rates; developed long-run avoided costs, including externalities, for use in screening Demand Side Measures.

1991 Massachusetts Electric Company

Prepared testimony for fuel switching case which analyzed marginal cost of Boston Gas Company, comparability of marginal cost estimation of electric and gas utilities.

1991 North Attleborough Gas Company

Assisted Company in all phases of filing rate case, including testimony and settlement negotiations, development of three new rate classes, and in developing strategy for phasing in very large (over 100%) increase in rate base.

1991 Nantucket Electric Company

Applied load research data to develop detailed (daily) demand and revenue projections.

1991 Nantucket Electric Company

Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.

1991 Essex County Gas Company

Assisted Company in filing rate case, including development of labor allocator and other allocations, marginal cost analysis, rate design; prepared avoided cost for use in DSM program screening.

1991 Nantucket Electric Company

Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.

1991 Blackstone Gas Company

Prepared full rate case (first filed by the Company in 9 years); presented testimony, assisted in a settlement of the case with intervenors.

1990 Wakefield Municipal Light Department

Assisted gas division of WMLD with avoiding hundreds of thousands of rate increase from Boston Gas Company; presented testimony on errors in Boston Gas filing; analyzed distribution system of both utilities.

1990 Illinois Office of Public Counsel

Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.

1990 Berkshire Gas Company

Assisted company with development of a pilot DSM program, including directing the development of the screening tools, estimating long-run avoided costs based on daily dispatch of Company proposed supply portfolio, then in screening cost-effective measures.

| | |
|---|---|
| 1990 | Plattsburgh Municipal Light Department |
| | Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class. |
| 1990 | Colonial Gas Company |
| | Assisted Company in developing various analyses for rate case, including converting class sales data (which includes a billing lag) to weather-adjusted, calendar data for use in revenue normalization and rate purposes. Refined La Capra Associates cost allocation model and trained company personnel in use of model. |
| 1990 | Blackstone Gas Company |
| | Resolved long-run undercollection of gas costs; assisted company in negotiations with its major lender, developed long-run plan to resolve inappropriate debt. |
| 1990 | Mobile Gas Service Corporation |
| | Assisted Company in development of strategy with regard to marketing plan in which electric company made payments to customers and appliance dealers to cause customers to switch to electric heat; directed detailed analysis of marginal costs and benefits of the electric marketing program. |
| 1989 | Middleton Electric Light Department |
| | Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer. |
| 1989 | Berkshire Gas Company |
| | Assisted Company in EFSC case, performing both innovative demand and supply analyses. We demonstrated that improved methodologies showed that new pipeline contract was beneficial to ratepayers. |
| 1989 | Littleton Water and Light Department |
| | Updated Company's revenue allocation and rates to reflect new marginal- |

cost based wholesale power tariff.

| | |
|---|---|
| 1989 | Wakefield Municipal Light Department |
| | Advised company regarding gas supply planning; assisted in renegotiation of contract with Boston Gas Company. |
| 1989 | Essex County Gas Company |
| | Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design, introducing subsidized rates for low-income customers. |
| 1989 | Colonial Gas Company |
| | Designed rates in rate case filing; reorganized commercial and industrial rate classes. |
| 1989 | Boston Edison Company |
| | Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant. |
| 1988 | Reading Municipal Light Department |
| | Analyzed power supply options, determined least-cost options. |
| 1987 | Essex County Gas Company |
| | Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design. This case moved rates closer to seasonal marginal costs, and class revenues closer to allocated costs. Modified Company's existing dispatch model to produce additional results for rate case and planning purposes, developed model to estimate marginal distribution costs. |
| 1987 | Wellesley Municipal Light Plant |
| | Redesigned rates for municipal utility, including allocating costs, |

estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

1986 Colonial Gas Company

Redesigned Company rates according to allocated cost of service study, marginal cost principles.

1985 Colonial Gas Company

Developed daily gas dispatch model to simulate actual daily dispatch, calculate marginal gas costs by season, and allocate gas costs between users.

Exhibit LS-2

## *Allocation of Stranded Costs to COPCo*

| Source: OCA-IV-7 Page 2 | MWh | % Total | 4CP/kWH Ratio | Demand Allocation |
|---|---|---|---|---|
| Total Adjusted Electric Sales | 32,384,867 | 95.85% | | 95.95% |
| COPCo | 1,403,549 | 4.15% | 0.974524 | 4.05% |
| Total Adj Sales Incl COPCo | 33,788,416 | 100.00% | | 100.00% |

| **Wholesale Stranded Cost Allocation** | |
|---|---|
| Total Stranded Cost | 526,903 |
| COPCo Allocation | 4.05% |
| COPCo Stranded Cost | 21,340 |

Development of Demand/Energy Allocations

| 4-Peak Allocation, March 31, 1990 Study | Total | Other Utilities |
|---|---|---|
| A-1 | 6,333,754 | 107,165 |
| | 1.00000 | 0.01692 |

| Energy Allocation, March 31, 1990 Study | Total | Other Utilities |
|---|---|---|
| C-1 | 33,484,716 | 581,361 |
| | 1.00000 | 0.01736 |

| | |
|---|---|
| Ratio A-1/C-1 | 0.974524 |

## *Administrative & General Expenses ($000)*
## *Per Exhibit RAC-1 page 56 of 83*

| | | Total | Prod | Trans | Dist | Allocation |
|---|---|---|---|---|---|---|
| 920 | A&G Salaries | 72,808 | | 8,916 | 63,892 | TD Exp |
| 921 | Office Supplies | 84,562 | | 10,356 | 74,206 | TD Exp |
| 923 | Outside Services | 17,162 | | 2,102 | 15,060 | TD Exp |
| 924 | Property Insurance | 6,968 | 4,956 | 347 | 1,665 | PTD Rate Base |
| 925 | Injuries & Damages | 16,906 | | 2,070 | 14,836 | TD Exp |
| 926 | Employee Pensions & Benefits | 111,028 | 58,295 | 5,931 | 46,802 | PTD Exp |
| 928 | Reg Comm Exp - FPC | 0 | | 0 | 0 | TD Exp |
| 928 | Reg Comm Exp - PUC & FPC | 6,492 | | 795 | 5,697 | TD Exp |
| 929 | Duplicate Charges | (3,433) | | (420) | (3,013) | TD Exp |
| 930 | Misc General | 7,514 | | 920 | 6,594 | TD Exp |
| 931 | Rents | 4 | | 0 | 4 | TD Exp |
| 935 | Maintenance of General Plant | 875 | | | 875 | Direct |
| | Total | 320,886 | 63,251 | 31,017 | 226,618 | |
| | **Allocation Factors** | 1.00000 | 0.71125 | 0.04980 | 0.23895 | PTD Rate Base |
| | Per PECO=====> | 1.00000 | 0.52505 | 0.05342 | 0.42153 | PTD Exp |
| | Per FF1======> | 1.00000 | 0.66224 | 0.03597 | 0.30179 | PTD Exp |

## *A&G Per PTD Expense Allocation*

| | | Total | Prod | Trans | Dist | Allocation |
|---|---|---|---|---|---|---|
| 920 | A&G Salaries | 72,808 | 48,216 | 2,619 | 21,973 | PTD Exp |
| 921 | Office Supplies | 84,562 | 56,000 | 3,042 | 25,520 | PTD Exp |
| 923 | Outside Services | 17,162 | 11,365 | 617 | 5,179 | PTD Exp |
| 924 | Property Insurance | 6,968 | 4,956 | 347 | 1,665 | PTD Rate Base |
| 925 | Injuries & Damages | 16,906 | 11,196 | 608 | 5,102 | PTD Exp |
| 926 | Employee Pensions & Benefits | 111,028 | 73,527 | 3,994 | 33,507 | PTD Exp |
| 928 | Reg Comm Exp - FPC | 0 | 0 | 0 | 0 | PTD Exp |
| 928 | Reg Comm Exp - PUC & FPC | 6,492 | 4,299 | 234 | 1,959 | PTD Exp |
| 929 | Duplicate Charges | (3,433) | (2,273) | (123) | (1,036) | PTD Exp |
| 930 | Misc General | 7,514 | 4,976 | 270 | 2,268 | PTD Exp |
| 931 | Rents | 4 | 3 | 0 | 1 | PTD Exp |
| 935 | Maintenance of General Plant | 875 | 579 | 31 | 264 | PTD Exp |
| | Total | 320,886 | 212,845 | 11,639 | 96,402 | |

# Derivation of Labor Allocation Factor

**Per PECO**
**(Exhibit RAC-1 page 48)**

| | | |
|---|---|---|
| Production | $172,726 | 0.52505 |
| Transmission | $17,573 | 0.05342 |
| Distribution | $138,671 | 0.42153 |
| | | |
| Total | $328,970 | |

**Per FERC Form 1 Page 354**

| | | |
|---|---|---|
| Production | $172,726 | |
| Transmission | $9,382 | |
| Distribution | $49,570 | |
| Customer Accounts | $13,436 | |
| Customer Service & Info | $12,728 | |
| Sales | $2,978 | |
| Administrative & General | $68,150 | |
| | | |
| Total | $328,970 | |
| | | |
| Production | $172,726 | 0.66224 |
| Transmission | $9,382 | 0.03597 |
| Dist (Incl Cust & Sales) | $78,712 | 0.30179 |
| | | |
| Total PTD Excl A&G | $260,820 | 1.00000 |

***PECO Unbundled Rates***

***Total Revenues, 12 Months Ended 12/31/96***

Exhibit LS-4

| | | | | |
|---|---|---|---|---|
| 1 | | **Rate R** | **Total Retail** | **Total Retail** |
| 2 | **Per PECO Exhibit WFS-3** | | | **(Actual $, kWh)** |
| 3 | Fixed Dist | 34,094,765 | 74,975,794 | |
| 4 | Trans | 19,027,778 | 107,457,981 | |
| 5 | Var Dist | 197,238,388 | 448,592,595 | |
| 6 | Total T&D | 250,360,931 | 631,026,370 | |
| 7 | CTC | 184,252,788 | 885,970,790 | |
| 8 | Elec Gen | 100,293,974 | 534,537,820 | |
| 9 | Tot CTC&Gen | 284,546,762 | 1,420,508,610 | |
| 10 | Total "Sample" | 534,907,693 | 2,051,534,980 | |
| 11 | kWh | 3,760,457,002 | 20,298,147,101 | |
| 12 | | | | |
| 13 | **Per PECO (Gross-up to Revenue)** | | | |
| 14 | Total Revenue | 1,096,984,000 | 3,323,348,515 | **3,276,734,547** |
| 15 | Fixed Dist | 69,921,245 | 134,020,689 | 132,140,888 |
| 16 | Var Dist | 404,494,754 | 811,260,380 | 799,881,476 |
| 17 | Total Dist | 474,415,999 | 945,281,070 | 932,022,363 |
| 18 | Trans | 39,022,000 | 164,055,959 | 161,754,876 |
| 19 | Total T&D | 513,437,999 | 1,109,337,028 | 1,093,777,240 |
| 20 | CTC | 377,864,000 | 1,401,365,343 | 1,381,709,505 |
| 21 | Gen | 205,682,001 | 812,646,144 | 801,247,802 |
| 22 | CTC&Gen | 583,546,001 | 2,214,011,487 | 2,182,957,307 |
| 23 | kWh | 7,711,912,201 | 30,600,959,717 | **32,945,449,000** |
| 24 | | | | |
| 25 | **Avg Rates Per PECO** | | | |
| 26 | Total Revenue/kWh | $0.1422 | | $0.0995 |
| 27 | Fixed Dist | $0.0091 | | $0.0040 |
| 28 | Var Dist | $0.0525 | | $0.0243 |
| 29 | Total Dist | $0.0615 | | $0.0283 |
| 30 | Trans | $0.0051 | | $0.0049 |
| 31 | Total T&D | $0.0666 | | $0.0332 |
| 32 | CTC | $0.0490 | | $0.0419 |
| 33 | Gen | $0.0267 | | $0.0243 |
| 34 | CTC&Gen | $0.0757 | | $0.0663 |
| 35 | | | | |
| 36 | **Reallocation of A&G, GP PER OCA** | | | |
| 37 | Production | 57,525,000 | | 155,785,000 |
| 38 | Transmission | (7,111,000) | | (19,042,000) |
| 39 | Distribution | (50,414,000) | | (136,743,000) |
| 40 | | | | |
| 41 | **Unbundled Revenues with OCA Adjustment** | | | |
| 42 | Distribution | 424,001,999 | | 795,279,363 |
| 43 | Transmission | 31,911,000 | | 142,712,876 |
| 44 | Generation | 641,071,001 | | 2,338,742,307 |
| 45 | Total Rate | 1,096,984,000 | | 3,276,734,547 |
| 46 | | | | |
| 47 | **Unbundled Rates with OCA Adjustment** | | | |
| 48 | Total Dist | $0.0550 | | $0.0241 |
| 49 | Trans | $0.0041 | | $0.0043 |
| 50 | Generation | $0.0831 | | $0.0710 |
| 51 | Total Rate | $0.1422 | | $0.0995 |
| 52 | | | | |
| 53 | | | | |

Exhibit LS-5

## Estimated Recovery of Retail Stranded Costs Per OCA

| | | 1996 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Estimated Sales (MWh)** | 1.26% | 32,945,449 | 33,780,905 | 34,206,544 | 34,637,547 | 35,073,980 | 35,515,912 | 35,963,412 | 36,416,551 | 36,875,400 |
| **OCA Proposed Rates** | | | | | | | | | | |
| T&D | Constant | $0.0285 | $0.0285 | $0.0285 | $0.0285 | $0.0285 | $0.0285 | $0.0285 | $0.0285 | $0.0285 |
| Market | | | $0.0298 | $0.0333 | $0.0366 | $0.0387 | $0.0410 | $0.0421 | $0.0454 | $0.0475 |
| Generation A&G | | | $0.0035 | $0.0035 | $0.0036 | $0.0036 | $0.0037 | $0.0037 | $0.0038 | $0.0039 |
| Avoidable Generation Component | | | $0.0333 | $0.0368 | $0.0402 | $0.0423 | $0.0447 | $0.0458 | $0.0492 | $0.0514 |
| CTC | | | $0.0150 | $0.0148 | $0.0146 | $0.0144 | $0.0142 | $0.0141 | $0.0139 | $0.0000 |
| Total Rate | | | **$0.0767** | **$0.0800** | **$0.0833** | **$0.0852** | **$0.0874** | **$0.0883** | **$0.0916** | $0.0799 |
| **OCA Proposed Revenue ($000)** | | | | | | | | | | |
| T&D Per OCA | | $937,992 | $961,779 | $973,897 | $986,168 | $998,594 | $1,011,176 | $1,023,917 | $1,036,818 | $1,049,882 |
| Market revenues | | | $1,008,198 | $1,138,606 | $1,268,896 | $1,355,902 | $1,457,784 | $1,513,614 | $1,653,732 | $1,753,118 |
| Generation A&G | | | $117,057 | $120,042 | $123,019 | $127,054 | $130,002 | $134,006 | $137,986 | $142,084 |
| Avoidable Generation Component | | | $1,125,255 | $1,258,648 | $1,391,915 | $1,482,956 | $1,587,786 | $1,647,620 | $1,791,717 | $1,895,202 |
| CTC - Retail Allocation * | | | $505,563 | $505,563 | $505,563 | $505,563 | $505,563 | $505,563 | $505,563 | $0 |
| Total Revenue | | | **$2,592,597** | **$2,738,108** | **$2,883,646** | **$2,987,113** | **$3,104,525** | **$3,177,100** | **$3,334,099** | $2,945,084 |
| **Current Average Rate** | Constant | $0.0995 | $0.0995 | $0.0995 | $0.0995 | $0.0995 | $0.0995 | $0.0995 | $0.0995 | $0.0995 |
| Current Total Revenue | | $3,276,735 | **$3,359,828** | **$3,402,162** | **$3,445,030** | **$3,488,437** | **$3,532,391** | **$3,576,899** | **$3,621,968** | $3,667,605 |
| **Difference (Proposed - Current)** | | | **($767,231)** | **($664,054)** | **($561,383)** | **($501,324)** | **($427,866)** | **($399,799)** | **($287,869)** | ($722,521) |
| **Percent Change** | | | -23% | -20% | -16% | -14% | -12% | -11% | -8% | -20% |

* Total CTC of $526.903 million less $21.340 million wholesale allocation

Exhibit LS-6

# Development of Unbundled Pricing
# Rate R in 1999 Per OCA
# (Revised Exhibit WFS-1)

| Revenue Requirement | Per OCA* | Per PECO |
|---|---|---|
| Transmission | $31,911,000 | 39,022,000 |
| Distribution | $424,001,999 | 474,415,999 |
| Fixed Distribution | $69,921,245 | 69,921,245 |
| Variable Distribution | $354,080,754 | 404,494,754 |
| CTC | $141,385,868 | 377,864,000 |
| Avoidable Generation | $273,705,365 | 205,682,001 |
| Total | $871,004,233 | $1,096,984,000 |

**Residential Average Reduction From OCA Rates 21%**

| Transmission | % ** | Revenue | Billing | Rate |
|---|---|---|---|---|
| Up to 500 kWh | 0.678846 | $21,662,655 | 5,355,673,016 | 0.0040 |
| Over 500 kWh (w) | 0.157880 | $5,038,109 | 1,245,582,498 | 0.0040 |
| Over 500 kWh (s) | 0.163274 | $5,210,237 | 1,110,656,684 | 0.0047 |
| | | $31,911,000 | 7,711,912,198 | |

| Distribution | % | Revenue | Billing | Rate |
|---|---|---|---|---|
| Up to 500 kWh | 0.678846 | $240,366,304 | 5,355,673,016 | 0.0449 |
| Over 500 kWh (w) | 0.157880 | $55,902,269 | 1,245,582,498 | 0.0449 |
| Over 500 kWh (s) | 0.163274 | $57,812,181 | 1,110,656,684 | 0.0521 |
| | | $354,080,754 | 7,711,912,198 | |

| Avoidable Generation | % | Revenue | Billing | Rate |
|---|---|---|---|---|
| Up to 500 kWh | 0.678846 | $185,803,792 | 5,355,673,016 | 0.0347 |
| Over 500 kWh (w) | 0.157880 | $43,212,603 | 1,245,582,498 | 0.0347 |
| Over 500 kWh (s) | 0.163274 | $44,688,970 | 1,110,656,684 | 0.0402 |
| | | $273,705,365 | 7,711,912,198 | |

| CTC | % | Revenue | Billing | Rate |
|---|---|---|---|---|
| Up to 500 kWh | 0.678846 | $95,979,231 | 5,355,673,016 | 0.0179 |
| Over 500 kWh (w) | 0.157880 | $22,322,001 | 1,245,582,498 | 0.0179 |
| Over 500 kWh (s) | 0.163274 | $23,084,636 | 1,110,656,684 | 0.0208 |
| | | $141,385,868 | 7,711,912,198 | |

| Unbundled Per OCA | Total | Trans | Dist | Avoid'bl Gen | CTC |
|---|---|---|---|---|---|
| Up to 500 kWh | 0.1015 | 0.0040 | 0.0449 | 0.0347 | 0.0179 |
| Over 500 kWh (w) | 0.1015 | 0.0040 | 0.0449 | 0.0347 | 0.0179 |
| Over 500 kWh (s) | 0.1178 | 0.0047 | 0.0521 | 0.0402 | 0.0208 |

| Unbundled Per PECO | Current | Trans | Dist | Gen | CTC |
|---|---|---|---|---|---|
| Up to 500 kWh | 0.1305 | 0.0049 | 0.0513 | 0.0264 | 0.0479 |
| Over 500 kWh (w) | 0.1305 | 0.0049 | 0.0513 | 0.0264 | 0.0479 |
| Over 500 kWh (s) | 0.1491 | 0.0057 | 0.0595 | 0.0283 | 0.0556 |

* CTC allocated on A-1, A&G allocated on E-1

** Allocation to components per Company