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Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
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Harrisburg, PA 17120
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Re: R-00973953
PECO Energy Company
Application for approval of a Restructuring Plan
and Consumer Education Program

To Whom It May Concern:

Please accept for filing the original and 3 copies of the testimony of Dr. John B. Legler on behalf of the Department of the Navy in the above-captioned action. This is the third of three witnesses who will provide testimony for the Navy; the testimony of the first two witnesses was provided yesterday. Please do not hesitate to contact the undersigned if there are any questions.

Respectfully submitted,

AUDREY VAN DYKE
(Associate Counsel, Litigation)
Naval Facilities Engineering Command
Acting as Attorney for
the Secretary of the Navy
(202) 685-1931

DOCUMENT FOLDER

cc:(w/encl)
Service List (those who were provided with early copies of first two witnesses. The rest will get all three witnesses in one package)

120

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JUN 19 1997

PA PUBLIC UTILITY COMMISSION
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Before the

Pennsylvania Public Utility Commission

In the Matter of the Application of	)	
	)	
PECO ENERGY COMPANY	)	DOCKET NO. R-00973953
	)	
For Approval of its Restructuring Plan Under	)	
Section 2806 of the Public Utility Code	)	
	)	

Direct Testimony of

JOHN B. LEGLER

On Behalf of the

THE DEPARTMENT OF THE NAVY

Filed: June 20, 1997

Testimony of John B. Legler

Before The

Pennsylvania Public Utility Commission

DOCKET NO. R-00973953

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. John B. Legler, 1040 St. Andrews Court, Bogart, Georgia 30622.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Department of the Navy. I am under contract with the Rate Intervention of the U.S. Department of the Navy to perform utility cost of capital studies. My academic affiliation is professor of Banking and Finance in the Terry College of Business at the University of Georgia, Athens, Georgia. This testimony represents the opinion of the author. It carries no official endorsement by the University of Georgia.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. I received my B. A. with Honors in Economics from Allegheny College in 1962, and my M.S. and Ph.D. degrees in Economics from Purdue University in 1965 and 1967, respectively. I was an assistant professor of economics at Washington University, St. Louis, Missouri, where I also served as the Assistant Director of the Institute for Urban and Regional Studies from 1966-1971. I joined the University of Georgia faculty in the Fall of 1971 as an associate professor of banking and finance. From 1971 to 1974, I served as administrator of the Research Division in the Institute of Government in addition to my teaching duties in the Department of Banking and Finance. I became Director of the Georgia Economic Forecasting Project on July 1, 1974 and served in that capacity until September 15, 1982. I was promoted to full professor in 1977. I have been a consultant to federal, state and local government agencies in Alabama, Arizona, California, Connecticut, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Rhode Island, South Carolina, Texas, Utah, Virginia and Washington. My consulting has been mainly in areas of economic forecasting, governmental finance, and the cost of capital. I have testified before the House Utilities Study Committee of the Georgia Legislature, the State Board of Equalization in Georgia, the Chatham County (Savannah) Superior Court, and the National Association of Security Dealers.

My publications include many articles in professional journals, books and monographs. I am a member of Beta Gamma Sigma, a business honorary. I am a research associate of the National Bureau of Economic Research, Inc.

Q. HAVE YOU SUBMITTED TESTIMONY IN OTHER HEARINGS BEFORE PUBLIC SERVICE COMMISSIONS OR OTHER REGULATORY AGENCIES?

A. Yes, I have testified extensively before Commissions on the cost of capital. My participation in hearings before regulatory agencies is indicated in Schedule 1. This is my first appearance before the Pennsylvania Public Utility Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained to review and comment on the Company's rate of return testimony and to prepare a study on which to base an independent estimate of the Company's cost of capital to be presented to the Commission on behalf of the Department of Defense and all other Federal Executive Agencies. It is my understanding based on Mr. Brennan's testimony that the cost rate at issue is to be used to compute stranded investment.

Q. HAVE YOU REVIEWED THE TESTIMONY ON THE COST OF CAPITAL SUBMITTED BY PECO ENERGY COMPANY IN THIS CASE?

A. Yes, I have. I have reviewed the testimony of Mr. Joseph F. Brennan presented on behalf of the Company. Mr. Brennan and I have appeared in several of the same cases over the years, and I believe that we are reasonably familiar with each others testimony. We agree on some issues and disagree on others.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON THE APPLICATION OF FINANCE THEORY TO THE REGULATORY PROCESS BEFORE DEVELOPING YOUR ESTIMATE OF THE COST OF EQUITY?

A. It is my opinion that the application of finance theory can provide help and guidance in the decision process, but that the issue of the fair rate of return is still largely judgmental. This is particularly true with respect to the return on equity component of the overall rate of return. Each finance theory suffers from the necessity of making crucial assumptions requiring judgment in the process of its application. Although proponents of any particular theory tend to minimize or even overlook the importance of the necessary assumptions, often the assumptions that are necessarily made are crucial to their results. It is for this reason that I use several methods to estimate the cost of equity capital, using one method to check on the reasonableness of another. In addition, using several methods enables me to estimate a range rather than a single value for the rate of return on equity. I believe that providing the Commission with a zone of reasonableness with respect to the cost of equity capital permits the Commission the flexibility of weighing other factors such as the rate base and capital structure in its decision, with the assurance that the estimate of the cost of capital is within a reasonable range. I believe that, should this Commission adopt my recommendation, the Company would be afforded the opportunity to earn a fair rate of return consistent with the Hope and Bluefield decisions.

It is also my opinion that reasoned judgment is important at this time because of the volatility in the markets. The results of mechanical approaches to estimating the cost of equity are likely to change even on a daily basis. While these changes in the calculated cost of equity may be relevant for market investment decisions, I believe that estimating the cost of equity for ratemaking purposes must take a longer term view.

Q. HOW DO YOU PROPOSE TO ORGANIZE YOUR TESTIMONY?

A. My testimony is divided into the specific tasks necessary to arrive at the overall cost of capital. First, I adopt an appropriate capital structure. Next, I adopt cost rates for senior capital, long-term debt and preferred stock. Next, I develop a cost rate for common equity. Then, I calculate the overall cost of capital, on a pre-tax and post-tax basis, by applying the component cost rates to my adopted capital structure. Following the estimate of the cost of capital, I discuss Mr. Brennan's comments on the past investor-experienced returns on common equity and shareholder recovery of stranded investment.

Capital Structure

Q. WHAT CAPITAL STRUCTURE DO YOU ADOPT FOR PURPOSES OF CALCULATING A WEIGHTED AVERAGE COST OF CAPITAL?

A. I have consistently supported the updating of capital structures in my testimony on the cost of capital. In this case, the most recent capital structure available to me is the capital structure as of December 31, 1996 as shown in Mr. Brennan's Exhibit, Schedule 1. That capital structure was provided to Mr. Brennan by the Company. It consists of 46.4% debt, 3.0% preferred stock and 50.6% common equity.

I agree with Mr. Brennan that a utility company should have some flexibility in managing its capital structure, and that an actual capital structure should be used unless it can be shown that it is imprudent or unreasonable. In my opinion, the reasonableness of a company's proposed capital structure can be measured by comparisons with similar companies in the same industry. In this regard, I have compared PECO's capital structure with other electrics with BBB/Baa bond ratings. The comparisons are based on Value Line data and are shown in Schedule 6 of my Exhibit. Based on the broad sample of BBB/Baa electrics, PECO's projected equity ratio for 1997 is 50.0% compared to the average ratio of 46.6%. Although PECO's equity ratio is above average, it is well within the upper and lower bounds of the equity ratios of the individual companies. A similar comparison of PECO with the group of BBB/Baa companies ultimately used in my DCF analysis is also shown in Schedule 6. The average projected 1997 equity ratio for this smaller group of BBB/Baa electrics is 45.5%. Judged by these standards, I find PECO's equity ratio to be reasonable, and to have somewhat lower financial riskiness compared to the group of BBB/Baa electrics.

For purpose of calculating a weighted average cost of capital, I will accept the Company's proposed capital structure. I do recommend that it be updated, if possible.

Cost of Debt

Q. WHAT IS THE BASIS FOR DETERMINING THE COST OF DEBT?

A. The cost incurred by the Company for debt is determined in the capital market at the time the debt is issued. Once issued, the debt becomes, in effect, a contractual arrangement between the Company and the investor. The cost will remain constant during the term of the investment and will not be altered by changes in the Company's financial integrity or general economic conditions. Thus, the cost of debt is the weighted average cost of the Company's embedded debt.

Q. WHAT COST RATE HAVE YOU ASSIGNED TO THE COMPANY'S LONG-TERM DEBT?

A. I have consistently adopted the position that embedded cost rates should be updated for known and measurable changes. The most recent embedded cost rates I have available are the rates as of December 31, 1996 as shown in Schedule 1 of Mr. Brennan's Exhibit. The cost rate for long-term debt is 8.47%, and the rate for MIPS debt is 9.21%. The rate shown for preferred stock is 7.70%. These rates were provided to Mr. Brennan by the Company and reflect issuance, selling expenses, as well as call and tender costs. I assume that they were calculated consistent with Commission practice. It has been my experience that there usually is little, if any, controversy regarding embedded cost rates for senior securities where the rates are historical as opposed to projected. For purposes of calculating a weighted average cost of capital, I will accept these rates.

Cost of Equity

Q. PLEASE DESCRIBE THE METHODS YOU USE IN ESTIMATING THE COST OF EQUITY CAPITAL FOR PECO ENERGY COMPANY.

A. I have used two methods to estimate the cost of equity capital: (1) applications of finance theory, and (2) the comparable earnings approach. There are several applications of finance theory that may be considered: (1) the Capital Asset Pricing Model (CAPM), (2) the bond yield plus risk premium method, and (3) the dividend yield plus growth or simply the DCF method. The traditional comparable earnings method estimates the rate of return directly by analyzing rates of return on book equity earned by other companies with similar risks. The applications of finance theory rely on data on stock market returns and are considered indirect measures. The ultimate task requires that these returns on market be translated into return on book for regulatory purposes.

Q. ARE THESE THE SAME METHODS YOU HAVE USED IN COST OF CAPITAL TESTIMONY IN YOUR APPEARANCES BEFORE COMMISSIONS?

A. Yes, they are. Over the years I have made certain refinements in my testimony, but the basic methods remain the same. In recent years, my risk premium analyis has been further expanded by using the CAPM as one basis for estimating expected returns. I also have applied the risk premium method to Moody's 24 Electrics. Also, despite my reservations about the Capital Asset Pricing Model, as well as recent literature questioning beta as a measure of risk, its usage in rate cases is increasing, and I have made estimates of the cost of equity based on it.

Discounted Cash Flow Method

Q. DID YOU USE THE "DIVIDEND YIELD PLUS GROWTH RATE METHOD" TO ASSIST IN ESTIMATING THE COST OF EQUITY FOR PECO ENERGY ENERGY COMPANY?

A. Yes, I did.

Q. PLEASE EXPLAIN THE METHOD AND HOW YOU USED IT IN THIS CASE.

A. This method recognizes that investors in stocks expect to receive total returns consisting of dividends and capital gains. Although investors may in fact suffer capital losses, it is reasonable to assume that most investors would not buy a common stock unless there were reasonably good prospects that the stock would increase in value over time. The basic equation used to describe this method, which is commonly known as the DCF method and is widely used in rate of return testimony, is:

$$k = D_1/P_0 + g$$

where,

k = the cost of equity

D_1 = the dividend next period

P_0 = the market price of the stock

g = the expected growth rate.

This is a "constant growth model"; and in its simplest form it is assumed that a company has a constant payout ratio and its earnings are expected to grow at a constant rate. Thus, if a stock has a market price of $30 a share and an expected annual dividend in the coming year of $3 a share, and if its earnings were expected to grow at 5% a year, then the cost of equity for the company is the 10% dividend yield plus the growth rate of 5% or a total of 15%.

Q. DO YOU BELIEVE THAT THE ANNUAL VERSION OF THE DCF MODEL IS ADEQUATE FOR MEASURING A UTILITY'S COST OF EQUITY?

A. Yes, I do. The annual version of the DCF model typically is criticized for its failure to recognize that dividends are paid on a quarterly basis. In my opinion, it is important to remember the context in which the DCF model is being used. Essentially, the purpose of estimating the cost of equity is to enable the calculation of the revenues required to meet investors' return requirements. The ultimate question is with respect to the adequacy of the revenue dollars to meet those requirements. While it may be argued that reinvestment of quarterly dividends during the year has the effect of raising investors' expected returns compared to the returns produced by the annual version of the model, the reinvestment of earnings during the year also will provide additional compensation to investors. Clearly, dividends are not paid at the end of the year, but neither do ratepayers pay their bills at the end of the year. The irrelevance of the quarterly adjustment is considered in the professional literature in an article by Charles M. Linke and J. Kenton Zumwalt, "The Irrelevance of Compounding Frequency in Determining a Utility's Cost of Equity," which appeared in Financial Management, Volume 16, Number 3 (Autumn 1987), pages 65-69.

As a practical consideration, the accuracy of a quarterly dividend version of the DCF model depends on the validity of the assumptions made regarding the pattern of dividends and the timing of dividend increases. Obviously, it is invalid to assume that the quarterly dividend is increase each and every quarter. The computationally easy version of the quarterly model makes this assumption. A more rigorous version of the model assumes that the dividend will be increased once a year. If this is the assumption, the quarter in which the dividend is increased relative to the point in time the DCF estimate is calculated is relevant.

Marvin Rosenberg and Ronald N. Lafferty in an article, The FERC's Discounted Cash Flow: The Right Direction Without Compromise," Public Utilities Fortnightly, February 4, 1988, pages 46-48, demonstrate that the quarterly dividend DCF model equates to the annual version of the DCF model with an adjustment of half the annual dividend growth. That is:

$$k = D_0(1 + .5g)/P_0 + g$$

Thus, if a stock has a market price of $30 a share and if the last annual dividend paid was $3 a share, and if its earnings were expected to grow at 5% a year, then the cost of equity for the company is an adjusted dividend yield of 10.25% plus the growth rate of 5% or a total of 15.25%.

Based on these considerations, I believe that the annual version of the DCF model is adequate for the purposes it is intended and the context in which it is used.

Q. DO YOU BELIEVE THAT THE CONSTANT GROWTH VERSION OF THE DCF MODEL IS ADEQUATE FOR PURPOSES OF ESTIMATING THE COST OF EQUITY?

A. Yes, I do, but certainly the results must be used with judgment in setting the cost of equity. The constant growth version of the model assumes that a company's dividends, earnings, book value and stock price increase at the same constant rate. I agree that dividends, earnings, and stock prices are not likely to grow at the same rate as required by the model. Indeed, the model can be modified to incorporate more than one growth rate. But this certainly adds to the mathematical complexity of the model and further complicates an already complicated process of selecting the growth rate.

I believe that it is important to consider what version of the model is likely to be used by investors themselves, not what another witness or I believe to be more acceptable. In this regard, I doubt that the average investor has the ability or inclination to attempt the mathematics required by the multiple growth version of the model. Under the constant growth version of the model it is relatively easy to determine the reasons for the differences in results among the witnesses which should benefit the Commission in its deliberations.

Q. HOW HAVE YOU APPLIED THE DCF MODEL IN THIS CASE?

A. Usually I apply the DCF model to the company under review and a group of reasonably comparable utilities of the same general type. I believe that this is satisfactory even in cases where the company is a subsidiary if it is wholely owned by the parent and dominates the parent's operations. Accordingly, I have applied the DCF model to PECO Energy Company and a group of reasonably comparable electric utilities. I believe that Mr. Brennan and I can agree that it would be inadequate to simply apply any of the financial models just PECO Energy Company. We both have applied the model to a group of electrics which, in our respective opinions, on average, approximates the riskiness of PECO.

Q. HOW DID YOU SELECT THE GROUP OF COMPARABLE ELECTRIC COMPANIES?

A. The group was selected from the electric utilities followed by Value Line. To be included in the group, a company had to have a BBB/Baa bond rating, the same rating as PECO. Additional screening criteria could have been applied, but I chose to make my estimates based on this broad group and then adjust for risk differences between PECO Energy Company and the group.

Mr. Bennan chose the opposite approach. He screened companies for comparability based on several risk indicators and selected a group in his judgment comparable in riskiness to PECO. I believe that his risk measures are appropriate, although several of the companies (American Electric Power, CINergy, DTE, and PP&L) in his group of comparables with single-A ratings would not have been considered for inclusion in my group of comparables. He was left with nine companies he deemed comparable. I was ultimately left with ten companies. Mr. Bennan and I both recognize that it is very difficult to find companies that fit the risk criteria exactly and some compromise is necessary.

Q. PLEASE CONTINUE WITH YOUR DISCUSSION OF THE DCF METHOD.

A. The most difficult aspect of implementing the DCF method is estimating the future growth rate. If a company's past trend in growth has been erratic, it is difficult to project future growth on the basis of past trends. Since the DCF method requires a constant or sustainable growth rate, it is apparent that growth rates based upon recent realized rates are too volatile to provide a basis for future projections for most utilities.

Q. ARE THERE OTHER METHODS OF FORECASTING GROWTH RATES?

A. Another method used by security analysts is to estimate future growth based on the percentage of retained earnings and the rate of return on book equity. Quite simply, if we call the percentage of earnings retained (b), and multiply it by the rate of return on equity (R), the estimate of future growth (g) is: $g = b \times R$. For example, if a company earns 10% on equity, but pays all the earnings out in dividends, the "plowback" factor will be zero and earnings per share will not grow. Conversely, if the company retains all of its earnings and pays no dividend, it would grow at an annual rate of 10%.

Q. DOES THIS PROCEDURE FOR ESTIMATING FUTURE GROWTH REQUIRE ANY ASSUMPTIONS?

A. Three assumptions must hold for the procedure to produce an accurate (exactly correct) estimate:

1. The rate of return on equity is constant over time.
2. The percentage of retained earnings is constant over

time.

3. The company sells no new common stock or sells it only at book.

While these assumptions have not held in the past for most utilities in general, it is the future, not the past, that is relevant. Also, while year to year fluctuations in the variables may be expected, the average return on equity and retention rate over time may be expected to be reasonably stable.

If a company were to sell common equity at above book value, proceeds from the sale possibly could be used to support a somewhat higher growth rate than suggest by the basic equation. Since most utility stocks are now selling well above book value this is more of a consideration than when utility stocks were selling below book value. For this reason, I do not believe exclusive reliance should be placed on this method of estimating the dividend growth rate at this time.

In my opinion the retention growth rate method provides a useful check on the sustainability of adopted growth rates. For any particular growth rate, the combinations of retention rates and returns on equity necessary to produce that growth rate can be determined. For example, we can see from the table below that for a growth rate of 6%, with retention rates of 25% to 40%, returns on equity from 15.0% to 24.0% must be sustainable.

<u>Retention Rate</u> x	<u>Return on Equity</u> =	<u>Growth Rate</u>
25%	24.0%	6.0%
30	20.0	6.0
35	17.1	6.0
40	15.0	6.0

In my opinion these returns and retention rates are unlikely on a sustainable basis. Accordingly, the acceptability of a 6.0% or higher growth rate in DCF calculations is questionable, and I believe even my estimates for individual companies reflecting growth rates above this level should be viewed with some skepticism.

Q. HAVE YOU APPLIED THIS TECHNIQUE TO PECO ENERGY COMPANY AND YOUR GROUP OF COMPARABLE ELECTRIC UTILITIES?

A. Despite its limitations, it is still useful and I have applied it in this case. To apply it, we need two numbers, a company's expected retention rate and an estimate of its future return on common equity. <u>Value Line</u> forecasts a longer-term (2000-2002) earnings and dividend estimate for PECO Energy Company and each company in the group of comparables. <u>Value Line</u> also forecasts a longer-term (2000-2002) return on common equity for each company. I have used these <u>Value Line</u> projections to calculate the retention growth for PECO Energy Company and each company in the group of comparables. In applying the formula, I have increased <u>Value Line's</u> return on equity by 0.5% to reflect conversion from a year end to an average year basis.

Q. HAVE YOU EMPLOYED ANY OTHER GROWTH RATES IN YOUR DCF ANALYSIS?

A. Yes, I have also made DCF estimates based on Value Line's direct dividend forecasted growth rate, and the average 5-year historical growth rate in earnings and dividends.

Q. WHAT PRICES WILL YOU ADOPT FOR PURPOSES OF YOUR DCF ESTIMATES?

A. The price of a stock is likely to fluctuate from day to day because of market conditions and factors such as dividend payments. In my opinion, in applying the DCF method to a single company, it would be appropriate to use the average price of the Company's stock over a period of time rather than the price on a particular day. The time period is admittedly judgmental, but it is my opinion that it is still better than a spot price. The use of a spot price in a situation where there are wide swings in the stock market over relatively short periods of time makes the resulting DCF calculation very much dependent upon the particular day chosen to perform the analysis. While the most recent stock price may be quite relevant for market investment decisions based on DCF calculations, I believe the use of the DCF method for ratemaking purposes must take a longer term view.

I have consistently used three month average prices in my DCF analysis in testimony. I have also provided estimates using the closing prices on the last day of the three month period. I will continue my practice in this case. I believe that these prices are reflective of current market conditions while the average price smooths out day to day fluctuations. The current time period in this testimony is March through May 1997.

Q. WHAT DIVIDENDS DO YOU ADOPT FOR PURPOSES OF THE DCF CALCULATION?

A. Conceptually, the appropriate dividend is the expected dividend for the coming year. Defined as D_1, it is equal to the current dividend times 1 plus the growth rate [$D_1 = D_0(1+g)$]. I believe the straight forward calculation suggested above reflects a reasonable approach to estimating the dividend for the coming year for the group of companies used in the DCF analysis. PECO has raised its dividend in the fourth quarter of each of the last several years. It raised the dividend to $.45 a share in the fourth quarter of 1996. Assuming two quarters at $.45 a share and two quarters at $.465, the annualized dividend would be $1.83. I believe that $1.83 is a reasonable estimate of the dividend for the coming year.

Q. WHAT EXPECTED RETURN DID YOUR DCF ANALYSIS PRODUCE FOR PECO ENERGY COMPANY?

A. Stock prices for PECO Energy Company are shown in Schedule 4. For the March through May 1997 time period, the average of the average monthly high and low prices is $20.25. PECO's closing price on May 30, 1997 was $19.000.

Value Line projects a dividend of $1.84 and an earnings per share of $2.55 for the 2000-2002 time period. This implies retention ratio of about 28%. As shown in Schedule 2, PECO'S historical retention rate has averaged about 21% for the 1981-1996 time period. Value Line projects a return on book equity of 10.05 for the 2000-2002 time period. Using a retention ratio of 28% and a return on book equity of 11.0% (adjusted by 0.5% for conversion to an average year basis), results in a retention growth rate of 3.1%. Value Line's direct estimate of the dividend growth rate is 2.0%, and its estimate of the earnings growth rate is 2.5%. I believe a long-term growth rate in a range of 2.0% to 3.0% is reasonable.

Using a dividend of $1.83, a stock price of $20.25 results in a dividend yield of 9.0%. Combining this dividend yield with a growth rate of 2.0% to 3.0% results in a DCF estimated return for PECO 11.0% to 12.0%. Based on the May 30, 1997 closing price of $19.000, the range is 11.6% to 12.6%.

Q. WHAT COST OF EQUITY DID YOUR DCF ANALYSIS PRODUCE FOR THE GROUP OF BBB/Baa RATED ELECTRICS?

A. The results are shown on Schedule 5. For the electrics, the projected dividend yield based on retention growth and average prices was 6.76%. Retention growth averaged 4.19% resulting in an average expected return on common equity of 10.95%. Based on Value Line's direct dividend growth rate forecast, the average expected dividend yield was 6.73% and the average dividend growth rate was 4.20% resulting in an average expected return on equity of 10.93%. As explained below, I have excluded expected returns for BBB/Baa rated electrics which are below the currently prevailing yield on Baa rated public utility debt (7.86% as of May 20, 1997). The expected returns based on May 30, 1997 stock prices are 10.84% and 10.83%, respectively.

In my opinion, companies for which the results produced estimates below the current yield on Baa utility debt (7.86%) should be deleted from the sample. The argument for such exclusion is simply that investors wouldn't buy a company's stock if its expected return is less than the return on its bonds.

Estimates based on average 5-year historical growth in earnings and dividends are shown on page 3 of Schedule 5. Only five companies passed the additional screening of average positive growth in earnings and dividends for the last five years. Based on May 30, 1997 prices the average expected return using historical growth was 12.23%. Based on average prices for the March-May 1997 period, the average expected return was 12.34%.

Q. DO YOU BELIEVE THAT THESE AVERAGE EXPECTED RETURNS ON COMMON EQUITY ARE APPROPRIATE FOR PECO ENERGY COMPANY?

A. I would not recommend this approach for estimating the expected return on equity to any individual company without examining the factors influencing a particular company. I do believe, however, that the averages are useful in forming a judgment about PECO Energy Company's cost of equity. Although the companies are similar in certain respects, we would expect there to be some differences in perceived riskiness of the individual companies, and accordingly, would expect some variation in the estimated cost of equity by company.

Q. HAVE YOU EXAMINED THE RELATIVE RISKINESS PECO ENERGY COMPANY IN COMPARISON TO THE GROUP OF COMPARABLE ELECTRIC UTILITIES?

A. Yes, I have. Risk differences may be divided into financial risk and business risk. Financial risk, as I am sure this Commission is aware, is concerned with the proportion of debt in a company's capital structure. The higher the proportion of debt, or conversely the lower the proportion of common equity, the greater the financial risk. As shown in Schedule 6, the average common equity ratio for the group of BBB/Baa rated electric companies was estimated at 42.5% in 1996 and is projected by Value Line to be 46.6% in 1996. For the group of comparable electrics used in my DCF analysis, the average equity ratio was 43.6% in 1996 and is projected to be 45.5% in 1997. By comparison PECO's equity ratio is estimated at 49.9% in 1996 and projected at 50.0% in 1997. Based on these ratios, PECO's financial risk in somewhat lower than the group of comparables, on average.

Business risk in a formal sense is defined as the uncertainty involved in the projections of future operating income. Many things can affect business risk and in the case of a utility, the size and economic base of a company's territory certainly would be one. General risk indicators for the BBB/Baa rated electrics are shown on page 1 of Schedule 7. These measures are Value Line's beta, Safety Ranking, Financial Strength Rating and Price Stability Index, and nuclear as a percentage of the fuel mix. Based on these measures of risk, PECO has a lower (less risky) Safety Rank, its Financial Strength also indicates lower risk. The other measures, beta, Price Stability, and nuclear exposure indicate greater risk. The risk indicators, on average, for the smaller group of companies used in the DCF analysis indicate the same general relationships, but indicate somewhat greater comparability between PECO and the comparison group. As was true of the group of companies used by Mr. Brennan, some indicators suggest that PECO is less risky than the group, others indicate greater risk. Overall, I believe that my group of companies reasonably approximates the riskiness of PECO.

Q. DO YOU SHARE MR. BRENNAN'S CONCERNS THAT THE DCF MODEL PRODUCES UNRELIABLE ESTIMATES OF A COMPANY'S COST OF COMMON

A. I share some of his concerns, and in recent cases I have given somewhat greater weight to the risk premium and CAPM estimates in making my recommendations. As I am sure, Mr. Brennan would agree that all of the financial models suffer from inherent problems, and no one model is superior to the others at all times. Mr. Brennan provides considerable testimony where he is critical of the DCF model, yet in making his recommendation it appears that he gave it equal weight with the CAPM. His recommendation appears to be a simple average of his DCF and CAPM results. Since he gave the DCF model equal weight in making his recommendation, it is hard to believe that he believes that his DCF estimate is unreliable. I agree that the DCF should not be abandoned, and agree with his position that a variety of methods should be used to estimate the cost of equity, and that judgment should be applied in making a recommendation. My testimony reflects this position, and includes a risk premium analysis in addition to the DCF and CAPM methods used by Mr. Brennan.

Risk Premium Method

Q. DID YOU USE THE "BOND YIELD PLUS RISK PREMIUM METHOD" TO ASSIST IN THE PREPARATION OF THE ESTIMATED COST OF EQUITY CAPITAL?

A. In virtually all the cases in which I have testified on the cost of capital I have utilized this method. Because of the volatile conditions in the bond market, there are problems with this method and its application in the traditional manner often used by analysts. I will discuss this method, the problems associated with it and why, at the present time, I do not believe exclusive reliance should be placed upon it for estimating the cost of equity. I do believe, however, that the Commission should give it consideration in setting the cost of equity. All methods suffer from the necessity of making assumptions and judgments in their application. The risk premium method is not exception.

Q. WHAT CONCLUSIONS HAVE YOU REACHED REGARDING THE RISK PREMIUM APPROACH?

A. I believe it should be used with care and be reflective of current conditions. Therefore, I believe it should not stand on its own but be used in conjunction with other estimating techniques.

Q. WHAT IS THE THEORETICAL BASIS OF THE BOND YIELD PLUS RISK PREMIUM METHOD?

A. Basically, the theory suggests that the required rate of return is higher for riskier securities than less risky securities. Thus, normally we would expect that corporate bonds would carry a higher cost than U.S. Government securities. Accordingly, corporate equity securities would have a higher return than its debt. The theory usually is implemented by adding a risk premium to the yield on a company's long-term debt or utility bonds of the same rating. The yield on the company's long-term debt would be established by market conditions; and relative riskiness of a company's bonds, basically, is assessed by bond ratings. Alternatively, a risk premium may be developed relative to a risk-free U.S. Government security and the cost of equity estimated by applying that risk premium to the currently prevailing rate on the government security.

Q. IS A COMMON EQUITY INVESTMENT IN A PUBLIC UTILITY INVARIABLY MORE RISKY THAN AN INVESTMENT IN THE DEBT OF A PUBLIC UTILITY?

A. Circumstances may exist such that a negative risk premium or well below average risk premium may be calculated. The conventional approach states that equity is more risky than debt because the equity holder stands last in line as a claimant on the earnings of a corporation. Bonds represent a long-term commitment at a fixed interest rate. The return on common equity is not fixed at the time of purchase and will change in response to changing financial and economic conditions. Thus, in the case of a regulated industry, the return on common equity may be adjusted to reflect current money cost more than likely with some lag. In the case of the bondholder, however, no adjustment in the interest rate takes place after the bond is issued. If the bondholder did not correctly anticipate future rates of inflation at the time of purchase, the transaction may turn out to be a poor investment despite the fact that interest payments continue and the principal is repaid at maturity.

This additional risk is called interest-rate risk. It has nothing to do with the financial condition of the company issuing bonds and can only be protected against by demanding a higher interest rate when the bond is issued. In my opinion, this is one important reason for the high interest rates experienced during the 1980s, despite substantial slowing in the rate of inflation. Investors recognize that interest rate risk is important and have demanded higher interest rates as protection against possible future worsening economic conditions and higher interest rates.

As a practical consideration bondholders have suffered low returns on public utility bonds for several decades despite the industry's good record of interest and principal payments. In my opinion, the perception that interest-rate risk is important has increased the relative riskiness of debt compared to equity.

Q. IS THE EXISTENCE OF A NEGATIVE RISK PREMIUM CRUCIAL TO YOUR REJECTION OF THE RISK PREMIUM METHOD AS THE PRIMARY METHOD OF ESIMATING THE COST OF EQUITY IN A RATE CASE.

A. No, it is not. The point of my risk premium discussion and presentation of data is not to establish a negative risk premium. The point that I am making is that the method as conventionally applied in rate cases may produce an unreliable estimate of the cost of equity. The conventional approach adds an average long-term risk premium calculated in a variety of ways to a current bond yield to arrive at a cost of equity. Implicitly, this assumes that the risk premium is constant. My analysis raises serious doubts about the validity of this assumption, and consequently, the usefulness of the method.

I do not disagree with the basic finance theory which indicates that investors expect higher returns on riskier investments. I do believe, however, that contemporary institutional market factors affecting relative risk should not be ignored for the sake of the simplicity found in historical relationships.

Q. DESPITE YOUR RESERVATIONS ABOUT THIS METHOD, HAVE YOU DONE ANY STUDIES OF RISK PREMIUMS FOR PECO ENERGY COMPANY OR THE GROUP OF COMPARABLE ELECTRICS?

A. Yes, I have prepared studies for PECO Energy Company and Moody's 24 Electrics as part of my testimony in this case. I have developed risk premiums based on a discounted cash flow approach and a Capital Asset Pricing Model approach. For the DCF based approach I based the necessary growth rate on Value Line's projected data for dividends per share, earnings per share and return on equity from its published reports on the companies towards the end of each year. In addition, I performed the same analysis using Value Line's direct forecasted dividend growth rates from those same reports. I also calculated a third set of risk premium estimates based on the Capital Asset Pricing Model. The Capital Asset Pricing Model is discussed later in my testimony. Thus, my risk premiums are based on three estimates of the returns on common equity. The dates of the Value Line reports and the necessary data are shown in Schedules 9, 10, and 11.

Q. WHAT RISK PREMIUMS DOES YOUR ANALYSIS INDICATE FOR PECO ENERGY COMPANY?

A. The results of my study are shown in schedules 10 and 11. The schedules may be viewed in the following way: an estimate of the cost of equity for PECO is made for the first of January of each year. It is then compared to the existing bond yield at the time which I have assumed to be the reported December Moody's public utility bond yield of the Baa rating class of the previous year.

Alternatively, the expected return is compared with the 30-year Treasury bond rate for December of the previous year. The expected risk premium is the difference between the DCF calculated return on equity and the then current bond yield, whether it is based on the Government bond rate or the utility bond rate. The estimated premiums are shown below.

	Based on Treasury Rate		Based on Utility Rate	
	1978-1997	1993-1997	1978-1997	1993-1997
Return based on:				
Retention Growth	4.33%	3.12%	3.08%	2.16%
Analysts' Growth	4.54%	5.01%	2.67%	3.61%
CAPM	5.20%	5.25%	3.22%	3.84%
Average	4.69%	4.46%	2.99%	3.20%

The calculated expected risk premium PECO Energy Company has averaged 2.99% relative to the utility bond rate and has averaged 4.69% relative to the Treasury bond rate for the period from 1978 to 1997 based on the three estimates of the returns on equity. The risk premiums for the last five years (1993-1997) averaged 3.20% relative to the utility bond yield and 4.46% relative to the Treasury rate. In calculating these average risk premiums, all negative risk premiums for individual years have been deleted.

The current yield on 30-year Treasury bonds is approximately

6.8% (6.82% as of June 9, 1997). The current yield on Moody's Baa rated public utility debt is approximately 7.9% (7.86% as of May 20, 1997). Thus, adding the average risk premiums for the 1978-1997 time period to current yields produces a required return in a range from 10.89% to 11.49%. Adding current yields to the shorter term risk premiums produces a required return in a range from 11.10% to 11.26%.

<u>Longer-term Risk Premiums</u>

6.8% + 4.69% = 11.49%

7.9% + 2.99% = 10.89%

<u>Shorter-term Risk Premiums</u>

6.8% + 4.46% = 11.26%

7.9% + 3.20% = 11.10%

Q. WHAT ARE THE RISK PREMIUM ESTIMATES OF THE COST OF EQUITY FOR MOODY'S 24 ELECTRICS?

A. I calculated the risk premium estimated returns for Moody's 24 electrics in the same manner as I did for PECO Energy Company. The average of the 24 electric's projected dividends, earnings and return on book equity taken from <u>Value Line</u> formed the basis for the retention growth rate. The average <u>Value Line</u> projected dividend growth rate was used as the analysts' projected earnings growth rate. The price and dividend data were taken directly from <u>Moody's Public Utility Manuals</u>. The risk premiums for the 1978-1995 period are shown in schedule 14 and are summarized below.

	Based on Treasury Rate	Based on Utility Rate
Return Based on:		
Retention Growth	3.98%	2.43%
Analysts' Growth	3.96%	2.41%
CAPM	5.19%	3.64%
Average	4.38%	2.83%

The calculated expected risk premium for Moody's 24 Electrics has averaged 2.83% relative to the utility bond has averaged 4.38% relative to the Treasury bond rate for the period from 1978 to 1997 based on the three estimates of the returns on equity.

The current yield on 30-Year Treasury bonds is approximately 6.8% (6.77% as of June 6, 1997). The current yield on Moody's single-A rated public utility debt is approximately 7.9% (7.88% as May 20, 1997). Thus, adding the average risk premiums for the 1978-1997 time period to current yields produces a required return in a range from 10.73% to 11.18%.

<u>Longer-term Risk Premiums</u>:

6.8% + 4.38% = 11.18%

7.9% + 2.83% = 10.73%

Q. SINCE YOU USED MOODY'S 24 ELECTRICS IN YOUR ANALYSIS, HAVE YOU COMPARED THE RISKINESS OF THIS GROUP WITH THAT OF PECO ENERGY COMPANY?

A. Yes, I have. The risk indicators for Moody's 24 Electrics are shown on Schedule 15. The common equity ratio for Moody's 24 Electrics for 1997 is 48.0% compared to PECO's 50.0%. Thus, based on financial risk, PECO Energy company is comparable (slightly less) risky compared to the average for Moody's 24 Electrics.

Based on the general risk indicators, PECO's beta is higher than the average for the group; its Safety Rating of 2 indicates somewhat lower riskiness compared to the group; its Price Stability Rating is slightly lower (slightly more risky) than the average. Its bond ratings indicates slightly higher risk compared to the group. Overall, based on measures of financial and business risk, I would judge PECO to be of comparable risk (slightly higher risk) compared to the group of Moody's 24 Electrics.

Capital Asset Pricing Model

Q. DID YOU USE THE CAPITAL ASSET PRICING MODEL (CAPM) TO ESTIMATE THE COST OF EQUITY TO PECO ENERGY COMPANY?

A. I consider the CAPM to be a subset of the risk premium approach. As with all the methods we use, assumptions are required in its application. There are fairly severe problems with the required data inputs usually employed by analysts using this method. This results in internal inconsistencies as I will discuss below. For this reason, I usually have preferred not to use this method in my testimony. Since the method has grown in popularity, I believe a comment on the use of this model is appropriate. I have also provided estimates of the cost of equity based on it.

Q. DID THE COMPANY'S WITNESS, MR. BENNAN USE THIS METHOD?

A. Yes, he did. In this case, Mr. Bennan and I have applied the CAPM approach in much the same manner. We have both used the long-term government bond yield as the risk-free rate, and have used Value Line betas. I have also used Standard & Poor's betas. We both have used a long-term historical market premium. We have also used a forward-looking market premium developed from Value Line data.

Much of the difference in our estimates using this method may be traced to the difference in the estimate of the risk-free rate we use and the composition of the sample of comparable risk companies. Other than the dating of our data, our estimates should be reasonably close.

Q. CAN YOU BRIEFLY DESCRIBE THE CAPITAL ASSET PRICING MODEL?

A. Very briefly, the model states that the cost of equity to a company is equal to a risk-free rate, usually approximated by the yield on a government security, plus a risk adjusted premium for equity compared to the risk-free rate. The risk adjustment factor is called beta, which is a measure of the relative volatility of the stock in question to the volatility of the market. The equation used to estimate the cost of equity is:

$$k_j = k_{rf} + \beta(k_m - k_{rf})$$

where, k_j is the return on the stock

k_{rf} is the risk-free rate

β is beta

k_m is the return on the market

Q. WOULD YOU BE MORE SPECIFIC ABOUT THE INTERNAL INCONSISTENCIES?

A. Yes, I will. The Value Line betas are commonly used in the implementation of the capital asset pricing model. The Value Line beta is an adjusted beta and the New York Stock Exchange Composite Index is used in its construction as a surrogate for the market. A long-term (1926-1995) historical market premium provided by Ibbotson Associates is often used as the surrogate for the expected market premium. The surrogate for the market in the Ibbotson study is the S&P 500. To the extent that the surrogate for the market and the estimating technique affect the beta, the estimated return will be affected. This may not be of great concern, but the use of an adjusted beta compared to a raw beta certainly affects the return substantially. The Value Line betas "are adjusted for their long-term tendency to converge towards 1.00." (Arnold Bernhard, How To Use the Value Line Investment Survey, page 61) The actual adjustment procedure involves the application of a regression equation which may be closely approximated by averaging the raw beta with 1.0 giving twice the weight to the raw beta. All stocks are adjusted in the same manner and also they are rounded to .00 or .05.

While the adjustment procedure may be appropriate for the construction of a risk indicator, the theoretical linkage between the adjusted beta and the CAPM model is tenous, at best. I know of no recent empirical tests which indicate that the beta of all stocks converge towards 1.0 or even that utility stocks converge the same way as other stocks. The CAPM, unlike the DCF, is a one period model. Thus, even if a forward looking beta is appropriate, the adjustment to the raw beta is too large to be realized in the near term.

Furthermore, I also should note that the beta is estimated relative to a risk-free rate. The estimated beta will vary depending upon whether a short-term or long-term government security rate is used as the proxy for the risk-free rate. There has been growing support among analysts for the use of a long-term government security rate as a proxy for the risk-free rate when using the CAPM in regulatory proceedings. However, it is possible that the beta was estimated relative to a different risk-free rate or no risk-free rate at all. The market premium is often based on the long-term historical spread between realized market returns and risk-free rates.

The Ibbotson study covering a very long time period beginning in 1926 often is used in developing this estimate. That long-term risk premium through 1995 is 7.0%.

Q. DESPITE YOUR RESERVATIONS HAVE YOU CALCULATED THE COST OF EQUITY FOR PECO ENERGY COMPANY OR YOUR GROUP OF REASONABLY COMPARABLE ELECTRICS USING THE CAPITAL ASSET PRICING MODEL?

A. I have calculated the cost of equity for PECO Energy company as well as the group electric utilities. I have used the current yield on 30-year Treasury bonds as the risk-free rate. Consistent with my risk premium estimates, I will use a rate of 6.8%. I will also use the historical risk premium of 7.0% in my analysis. I have made the calculations using both S&P and Value Line betas. The average S&P beta for the group of electric companies used in my DCF analysis is .55, and PECO Energy Company's is .52. The average Value Line beta for the group of electrics is .78, and PECO's is .85. The betas are shown in Schedule 16. Based on the long-term historical market premium of 7.0% and a risk-free rate of approximately 6.8% for 30-year Treasury bonds, the CAPM estimated return for PECO is in a range from 10.68% to 12.50%; and in a range from 10.47% to 11.80% for the group of comparable electrics used in my DCF analysis.

PECO Energy Company:

6.8% + .52(7.0%) = 10.44%

6.8% + .85(7.0%) = 12.75%

Comparable Electric Companies:

6.8% + .55(7.0%) = 10.65%

6.8% + .78(7.0%) = 12.26%

Q. WOULD THE RESULTS CHANGE MATERIALLY IF YOU USE MR. BRENNAN'S GROUP OF COMPARABLE COMPANIES?

A. No, they would not. I have provided the S&P and Value Line betas for Mr. Brennan's group of comparable companies on page 3 of Schedule 16. The average S&P beta for the group is .64 and the average Value Line beta is .79. Thus, the CAPM results for his group of comparable companies based on updated betas and risk-free rate would be in a range from 11.28% to 12.33%.

$$6.8\% + .64(7.0\%) = 11.28\%$$

$$6.8\% + .79(7.0\%) = 12.33\%$$

Q. WOULD YOUR CAPM RESULTS HAVE BEEN MATERIALLY DIFFERENT IF YOU HAD USED A FORWARD LOOKING MARKET RETURN?

A. Yes, they would have been lower. The purpose of using a forward looking estimate of the market return is to determine a forward looking estimate of the market risk premium, the difference between the return on the stock market and the risk-free rate. One approach to estimating the market return is to use <u>Value Line</u> projections. I have provided the necessary data from the June 13, 1997 <u>Value Line</u> publication as Schedule 17. That publication indicates a median estimated dividend yield for the next twelve months for the dividend paying stocks covered by <u>Value Line</u> of 1.9%. <u>Value Line's</u> projected price appreciation of 1700 stocks over the next 3 to 5 years is 45%. Assuming the midpoint of that forward time period, four years, results in a growth rate of 9.7%.

$$(1.45)^{.25} - 1 = 9.7\%$$

Combining the expected dividend yield of 1.9% with the expected growth rate of 9.7% results in an expected market return of 11.6%. The expected market risk premium is the difference between the expected market return and the risk-free rate of 6.8%, or 4.8%. The 4.8% expected market risk premium is less than the 7.0% I used in my analysis. Accordingly, the CAPM results for PECO would have been from .59% [.52 x (7.0%-4.8%) = 1.295%] to 1.87% [.85 x (7.0%-4.8%) = 1.87%] lower.

<u>PECO Energy Company</u>

6.8% + .52(4.8%) = 9.30%

6.8% + .85(4.8%) = 10.88%

<u>Comparable Electrics</u>

6.8% + .55(4.8%) = 9.44%

6.8% + .78(4.8%) = 10.54%

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON MR. BRENNAN'S APPLICATION OF THE CAPM?

A. Yes, I do. Mr. Brennan states that the historical market risk premium for the 1926-1995 time period taken from the Ibbotson study cited on page 44 of his direct testimony is 7.3%. That risk premium is actually 7.0%. He is correct that the common stock return is 12.5%, but the long-term bond return is 5.5% not the 5.2% he used to calculate the risk premium. I have reproduced the page from the Ibbotson study showing these returns as Schedule 18 of my Exhibit. Based on the Value Line beta of .85 for PECO, this overstatement of the risk premium results in an overstatement of the CAPM return for PECO of 0.255% (.85 x 0.3% = .255%).

Comparable Earnings

Q. DR. LEGLER, YOU STATED THAT THE COMPARABLE EARNINGS APPROACH IS ONE METHOD OF ESTIMATING THE COST OF EQUITY CAPITAL. PLEASE EXPLAIN THE BASIS OF THIS APPROACH.

A. The basis of the comparable earnings approach is the often cited case of the Federal Power Commission vs. Hope Natural Gas Company (1944). Briefly, two principles are involved in the comparable earnings approach as applied to ratemaking. One states that an investor should be able to earn a return comparable to the returns available on alternative investments with similar risks. The other principle states that the return should be sufficient to enable the utility to attract additional equity capital required on a reasonable basis and maintain the financial integrity of the firm. Basically, the comparable earnings test is what economists refer to as the opportunity cost principle.

Q. WHAT PROBLEMS ARE INHERENT IN THE COMPARABLE EARNINGS APPROACH?

A. The major problem in applying the comparable earnings approach is the difficulty in determining what companies are comparable to the utility in question. Some analysts suggest that the valid comparison is with a broad sample of unregulated firms such as the S&P 400. Other analysts select groups of specific firms of comparable risk based upon criteria such as similar beta coefficients, and standard deviations of returns. In short, the problem is not so much the concept, but its implementation. In fact, it is these problems and the fact that the method is backward looking rather than forward looking which, at least in part, have led to the application of finance theory such as the DCF method in utility rate cases.

Q. DR. LEGLER, DO YOU BELIEVE THAT UTILITIES AND INDUSTRIALS ARE COMPARABLE?

A. In addition to the protection afforded by regulation to utilities, there are accounting differences in the measurement of returns which call into question strict comparability between utilities and industrials.

There is also a problem comparing utilities and industrials when there is a significant disparity in the market to book values. An illustration should make this point clear. If an industrial stock is selling for two times its book value, and earning 20% per year on book value, it would be erroneous to suggest that a new or prospective investor would receive a return of 20% on his or her investment. Thus, comparing book returns of utilities selling close to book to the book returns of industrials selling well above book is an invalid comparison. This is not to suggest, however, that the investor could not receive a market return of 20% on one or both investments. It is also less of a problem now that utility stocks such as Baltimore Gas & Electric are selling well above book value.

Q. WHAT CONCLUSION HAVE YOU REACHED REGARDING THE COMPARABLE EARNINGS APPROACH USING INDUSTRIALS AS THE ONLY STANDARD OF COMPARISON?

A. I reject the application of the comparable earnings approach using industrials as the only basis of comparison, in principle, because of the questionable comparability of the measured earnings and differences in risks of regulated and unregulated companies.

Q. DR. LEGLER, HAVE YOU PERFORMED AN ANALYSIS OF THE RETURNS OF COMPANIES COMPARABLE TO PECO ENERGY COMPANY?

A. The standard comparable earnings approach would consist of (1) selecting a sample of companies with comparable investment risks to the utility being analyzed; (2) calculating the return on book equity for this sample; and (3) using the return on book equity of the sample as a guideline for setting the return on book for the utility being considered. I have not performed this standard or traditional comparable earnings test in this case.

Q. WHAT TYPE OF COMPARABLE EARNINGS STUDY HAVE YOU PERFORMED?

A. My DCF analysis for the group of reasonably comparable electrics has the attributes of a forward looking comparable earnings analysis. Since it is a market based approach, the cost of equity for a group of comparable companies, or a risk adjusted cost of equity for a group of reasonably similar companies, if awarded to PECO Energy Company conforms to the Hope and Bluefield standards. Consequently, my DCF analysis parallels the traditional approach and leads to the same conclusion.

Q. BY LIMITING THE STUDY TO OTHER ELECTRIC UTILITIES AREN'T YOU INVOLVING CIRCULARITY IN YOUR REASONING?

A. No, if the study were limited to historical returns for the electric utility industry, circularity of reasoning would be a problem. By using a market based approach, it is assumed that the market accounts for differences in risk among companies and among industries in setting stock prices.

Q. HAVE YOU APPLIED ANY OTHER REASONABLENESS TESTS OF A COMPARABLE EARNINGS NATURE?

A. I have provided the Value Line projected returns for PECO Energy Company and the group of electric utilities for 1997, 1998 and 2000-2002 in Schedule 18. The average projected return for the group of electric utilities used in my DCF analysis for 1997 is 11.6%; for 1998 is 11.4%; and for the 2000-2002 time period is 11.0%. The average projected return for PECO 10.5% for 1997, 10.5% for 1998, and 10.5% for the 2000-2002 time period.

MARKET PRESSURE AND FLOTATION COSTS

Q. ESTIMATES DERIVED FROM THE BOND YIELD PLUS RISK PREMIUM APPROACH AND THE DCF METHOD ARE MARKET VALUE ESTIMATES OF THE COST OF EQUITY. SINCE COMMISSIONS REGULATE ON A BOOK VALUE BASIS, IS IT NECESSARY TO ADJUST THESE MARKET ESTIMATES TO PROVIDE A FAIR RATE OF RETURN ON BOOK EQUITY?

A. When a company sells a new issue of stock, certain flotation costs are involved, and in theory, there will be pressure on the price of the stock caused by its increased supply. Thus, in theory, if the allowed rate of return on book is set equal to the market cost of equity, a new stock issue would sell below book value. That is, the equity per share of current shareholders would be diluted. To protect against this dilution of capital, and permit the recovery of issuance expenses, theoretically, the return on book should be set somewhat above the market value cost of equity.

Q. WHAT THEORETICAL ADJUSTMENT IS REQUIRED?

A. In my opinion, the proper relationship is a highly complex problem. Some of the factors to be considered include the current state of the stock market, the volatility of the stock in question, the issuing company's earnings and dividend growth rate, its current market to book ratio, and the capital structure of the company. Further, if one purpose of the adjustment is to protect existing shareholders from dilution when new stock is sold, then the need for capital in the future (i.e., whether or not the company will be selling new stock) must also be relevant. Market pressure should be measured by taking into account consideration of the trend in the market. The decline in a company's stock at the time of issuance should be measured net of any general market decline. A study by John W. Bowyer, Jr. and Jess B. Yawitz, "The Effect of New Equity Issues on Utility Stock Prices," Public Utility Fortnightly, May 22, 1980, examined 278 public stock issues from 1973 through 1976. They found an average market pressure of 0.72%. Other studies include "Equity Issues and Offering Dilution," by Paul Asquith and David W. Mullins, Jr., in the January/February 1986 issue of the Journal of Financial Economics; and "Impacts of New Equity Sales Upon Electric Utility Share Prices," by Richard H. Pettway and Robert C. Radcliffe in the Spring 1985 issue Financial Management. These studies found market pressure based upon specific concepts of the general term of 0.9 percent and 3 percent, respectively. Other studies for individual utilities may be found in the testimony of rate of return witnesses in utility cases including my own.

Q. DR. LEGLER, WHAT ADJUSTMENT DO YOU BELIEVE IS NECESSARY?

A. I believe that the need for an issuance cost adjustment should be considered on a case by case basis. An adjustment should be considered when a company can demonstrate that it will issue additional common equity in the near future. Should the Company announce such plans, an adjustment should be considered by the Commission. I know of no such plans, and Mr. Brennan stated in his testimony on page 47 that he has no direct knowledge of any planned sales of new common stock by PECO. He correctly made no adjustment to his estimated cost of common equity for market pressure, selling and issuance expenses.

Cost of Equity Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR STUDIES OF THE COST OF COMMON EQUITY TO PECO ENERGY COMPANY?

A. I have relied on the discounted cash flow method, the risk premium method, and the capital asset pricing model. I have applied the DCF method to PECO Energy Company data and to a group of reasonably comparable electric utilities. I applied the risk premium method to PECO and Moody's 24 Electrics. I estimated the capital asset pricing model using PECO and the same group of electrics that I used in my DCF analysis.

The results of these financial models are shown below. These results are exclusive of a flotation cost or market pressure adjustment which I believe is unnecessary at this time. It has consistently been my position that the need for a market pressure-flotation cost adjustment should be considered on a case by case basis. PECO has not had a public offering in recent years, and to the best of my knowledge has no announced intentions of an offering. Therefore, in my opinion, there is no need to make such an adjustment in this case.

	PECO	Comparable Companies
DCF Method	11.50%	11.41%
Risk Premium Method	11.19%	10.96%
CAPM	10.85%	10.73%
Average	11.18%	11.03%

In summarizing the results of the three financial models, I have used the midpoints of the DCF estimates based on average prices. I have used the midpoints of the risk premium estimates, and the estimate for the comparable companies is based on Moody's 24 Electrics. The CAPM results also reflect the midpoint of the estimates based on the historical market risk premium and the expected market risk premium.

It is my opinion, that based on my studies discussed earlier, the cost of equity to the Company lies in a range from 11.2% to 11.5%. As is my practice, I am recommending a range rather than a point estimate. The results of the analyses suggest that PECO Energy Company is reasonably comparable in risk to group electric utilities used in my analyses, the the results of the financial models tend to confirm the relationship. The midpoints of all of the financial models suggest that the cost of equity to PECO is reasonably close to the average for the comparison group. For each financial model, the indicated cost of equity to PECO is somewhat higher than for the comparison group.

For purposes of calculating a weighted average cost of capital, I will use a cost rate for common equity of 11.4%, slightly above the average (rounded) of the midpoints of my applications of the financial models for PECO, and the midpoint of my recommended range.

Q. THE RESULTS OF YOUR APPLICATIONS OF THE FINANCIAL MODELS AND YOUR RECOMMENDED COST OF COMMON EQUITY ARE QUITE CLOSE TO THOSE OF MR. BRENNAN. DO YOU HAVE ANY COMMENTS ON THE APPARENT CONSISTENCY OF YOUR RECOMMENDATIONS?

A. Since we have applied the models in much the same ways, it should not be surprising that our results are reasonably close. Mr. Brennan suggested in his testimony that because of the volatility in the markets, his analyses and recommendation could require updating. In fact, the risk-free rate that we both use is the same despite the considerable time that has passed since he prepared his testimony. Although the rate is now at about the same level as it was when he prepared his testimony, it has been quite volatile since then. Actually, correcting his CAPM estimate for the overstatement of the market risk premium he used would put his estimate of the cost of common equity for PECO very close to mine.

Weighted Average Cost of Capital

Q. HAVING ASSIGNED COST RATES TO THE CAPITAL COMPONENTS AND ADOPTED A CAPITAL STRUCTURE, WHAT WEIGHTED AVERAGE COST OF CAPITAL DO YOU RECOMMEND?

A. Based on the capital structure as of December 31, 1996 consisting of 43.1% Long-term debt, 3.3% MIPS debt, 3.0% preferred stock and 50.6% common equity, an embedded cost of long-term debt of 8.47%, an embedded cost of MIPS debt of 9.21%, an embedded cost of preferred stock of 7.70% and a cost of common equity of 11.4%, the weighted average cost of capital is 9.95%. These calculations are shown in Schedule 20. On an after-tax basis assuming the Company-provided income tax rate of 41.493%, the cost rate is 8.31%.

Comments on Mr. Brennan's Checks on the Reasonableness of His Recommendation

Q. DO YOU AGREE WITH MR. BRENNAN'S CHECKS ON HIS MARKET-DERIVED COST RATE FOR COMMON EQUITY CAPITAL?

A. I do not believe that his checks confirm the reasonableness of his recommendation to the extent that they would preclude the reasonableness of other recommendations. Mr. Brennan proposes two checks, a comparison with authorized rates of return for electric utilities rendered during 1996, and a comparison of the interest coverage ratio implied by his recommendation with the level of coverages required by S&P to obtain an A and BBB rating.

He indicates that there were 22 different rate cases for electric utilities during 1996, and the average authorized return on equity was 11.4%. For the cases decided in the fourth quarter of 1996, the average authorized return was 11.6%. It should be obvious that such comparison is baseless for at least one important factor; that is, we have no idea about the comparability of risk between PECO and these companies. I believe that it is just coincidence that Mr. Brennan's recommendation in this case is close to recent authorized returns. I don't believe that this comparison tests the reasonableness of his recommendation in any meaningful way.

His second test compares the interest coverage ratio of 3.64 times implied by his recommendation with the levels required by S&P to obtain particular bond ratings. He states that S&P requires a coverage ratio of 4.15 times for an A rating and 3.15 times for a BBB rating. The midpoint of these required coverages, 4.15 times and 3.15 times, is 3.65 times. Mr. Brennan is suggesting that the midpoint is indicative of the coverage ratio required for a B++ rating. Using this logic it seems to me that it could just as well be indicative of the coverage required for an A- rating. There are two rating classes between an A and a BBB, A- and B++. Therefore, it would seem that a coverage of slightly less than 3.5 times would support a B++ rating.
I don't know where Mr. Brennan is obtaining the S&P rating criteria. As I understand them, S&P divides the major rating categories, AAA, AA, A, and BBB into "busines position" categories, above average, average, and below average. It would appear, that Mr. Brennan is equating the + (plus) and - (minus) designations to above average and below average categories.

Using Mr. Brennan's approach to calculating coverages, my recommendation would imply a pre-tax coverage ratio of 3.60 times which is not materially different than the ratio implied by his recommendation. Subject to my concerns about his interpretation of the S&P benchmarks, I believe that the pre-tax coverage ratio comparison supports my recommended return on common equity. Based solely on this criterion, I believe a return somewhat below my recommended 11.4% would support a B++ rating.

Q. DO YOU AGREE WITH MR. BRENNAN'S ANALYSIS OF SHAREHOLDER RECOVERY OF STRANDED INVESTMENT?

A. No, I do not. Essentially, Mr. Brennan is arguing that investors have not been compensated for the risk associated with the failure to recover stranded investment. His argument rests primarily on his analysis of shareholder returns since 1972. He disputes the findings of other researchers, and claims that electric utility shareholders have not enjoyed returns equal to those of industrial firms. In particular, he claims that PECO investors have fared poorly in comparison to investors in other electrics.

Most rate of return witnesses use market based approaches in estimating the cost of equity. The risk premiums implied by these methods are intended to capture all risks faced by investors. At any point in time some of those risks are known, but some are unknown. I believe that it would be improper to compensate current investors for risks that were not known when returns were set more than twenty years ago. I find return comparisons going back to the early 1970s irrelevant in assessing the cost of common equity today. If the Capital Asset Pricing Model has validity, we would expect the historical returns of electrics to be below the returns on industrial for this period anyway.

Mr. Brennan states that PECO investors expected to recover their investment and have an opportunity to earn a fair return on their investment. I don't dispute this, but certainly the possibilty of this not happening is one of the risks faced by equity investors. If Mr. Brennan is correct in his assertion that "Investors do not reflect elements of risk until there is the imminent prospect of such risk" [Brennan, Direct Testimony, page 51, lines 3-4], that is the investors' failure, and I see no justifiable reason for ratepayers to assume this risk. It is like saying, you will be compensated for assuming those risk you anticipate, but if you find you were wrong and missed some of the risks, come back and we will be take care of you. Furthermore, if Mr. Brennan is also correct that "the investment horizon of most common stockholders is but a few years and not ten or fifteen years" (Brennan, Direct Testimony, page 51, lines 4-5], the shareholders of the 1970s and 1980s are no longer shareholders assuming the risks reflected in the current regulatory environment.

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. BRENNAN'S COMPARISONS OF PECO'S RETURNS WITH THE RETURNS OF OTHER UTILITIES AND INDUSTRIALS?

A. Mr. Brennan updated the NARUC study discussed in his testimony for the 1992-1997 time period, and concluded on page 58, at lines 16 and 17, that "PECO fared worse than all other groups." He then goes on later in his testimony to propose a more appropriate method to determine whether electric utilities earned more than non-utility investors from cash paid by consumers. Although I don't find the comparison with non-utilities to be useful, he does report that for the 1992-1995 time period, PECO's cash return was 10.95% compared to 10.55% for the electrics [Brennan, Direct Testimony, page 61, lines 10-11].

From his analysis, Mr. Brennan draws two conclusions. First, "There is no basis for asserting that electric utility investors, most particularly PECO investors, were compensated for the risk of stranded investment during the period 1972-1992" [Brennan, Direct Testimony, page 61, lines 14-16]. As stated earlier, I believe this to be irrelvant. Second, he states "In addition, since 1992 the industrial index earned significantly more than all utilities studied" [Brennan, Direct Testimony, page 61, lines 16-17]. This also is irrelevant. If it is the strongest conclusion he can reach, I don't believe it makes a case for the point he is trying to make. If this is the more appropriate alternative analysis, his position is unsupported.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Before the

Pennsylvania Public Utility Commission

In the Matter of the Application of	)	
	)	
PECO ENERGY COMPANY	)	DOCKET NO. R-00973953
	)	
For Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code	)	
	)	

Exhibits of

JOHN B. LEGLER

On Behalf of the

THE DEPARTMENT OF THE NAVY

Filed: June 20, 1997

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Southern California Edison	CPUC 96-05-023	09/96
Southern California Gas Company	CPUC 96-05-024	09/96
Baltimore Gas & Electric	PSCM 8725	11/96

(a) Testimony filed, case settled.

PECO Energy Company: Dividends, Earnings & Retention Rate

Year	Dividends Per Share	Earnings Per Share	Retention Ratio
1981	$1.90	$2.25	15.6 %
1982	2.06	2.39	13.8
1983	2.12	2.40	11.7
1984	2.20	2.70	18.5
1985	2.20	2.56	14.1
1986	2.20	2.60	15.4
1987	2.20	2.33	5.6
1988	2.20	2.33	5.6
1989	2.20	2.49	11.6
1990	1.45	2.16	32.9
1991	1.23	2.15	42.8
1992	1.33	2.17	38.7
1993	1.43	2.45	41.6
1994	1.55	1.76	11.9
1995	1.65	2.52	34.5
1996	1.76	2.24	21.4
		Average	21.0 %
		Ave. (1986-1996)	23.8 %
		Ave. (1991-1996)	31.8 %

Source: *Value Line,* March 14, 1997.

PECO Energy Company: Growth Rates, Selected Time Periods

Time Period	Dividends Per Share	Earnings Per Share
1981-1991	-4.26 %	-0.45 %
1982-1992	-4.28	-0.96
1983-1993	-3.86	0.21
1984-1994	-3.44	-4.19
1985-1995	-2.84	-0.16
1986-1996	-2.21	-1.48
1981-1986	2.98 %	2.93 %
1982-1987	1.32	-0.51
1983-1988	0.74	-0.59
1984-1989	0.00	-1.61
1985-1990	-8.00	-3.34
1986-1991	-10.98	-3.73
1987-1992	-9.58	-1.41
1988-1993	-8.25	1.01
1989-1994	-6.76	-6.70
1990-1995	2.62	3.13
1991-1996	7.43	0.82
1981-1984	5.01 %	6.27 %
1982-1985	2.22	2.32
1983-1986	1.24	2.70
1984-1987	0.00	-4.79
1985-1988	0.00	-3.09
1986-1989	0.00	-1.43
1987-1990	-12.97	-2.49
1988-1991	-17.62	-2.64
1989-1992	-15.44	-4.48
1990-1993	-0.46	4.29
1991-1994	8.01	-6.45
1992-1995	7.45	5.11
1993-1996	7.17	-2.94

Source: Calculated from Schedule 2.

Exhibit___(JBL-1)
Schedule 4

PECO Energy Company: Stock Prices

	High	Low	Close
1996:			
January	$31.250	$29.750	$30.750
February	32.500	27.375	28.250
March	28.875	26.250	26.625
April	26.875	24.250	24.750
May	26.250	24.125	24.625
June	26.250	24.000	26.000
July	26.250	23.500	23.500
August	24.750	23.250	23.500
September	24.500	23.000	23.750
October	25.375	23.875	25.250
November	27.375	25.125	25.500
December	25.500	24.250	25.250
1997:			
January	$26.375	$22.250	$23.000
February	23.625	21.750	22.500
March	22.500	20.000	20.375
April	20.750	18.750	19.750
May	20.625	18.875	19.000

Source: Standard & Poor's Corporation, Stock Guide.

DCF Analysis: BBB/Baa Rated Electrics

Company	Current Dividend	Average Price March-May	Retention Growth (%)	Projected Dividend	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.875	2.60	$1.93	7.45	10.06
CMS Energy	1.20	32.563	7.87	1.29	3.98	11.85
Commonwealth Energy	1.58	21.125	5.27	1.66	7.87	13.14
DQE	1.36	28.188	4.33	1.42	5.03	9.37
Eastern Utility Associates	1.66	17.750	1.03	1.68	9.45	10.48
GPU, Inc.	2.00	33.063	4.96	2.10	6.35	11.31
Illinova Corp.	1.24	22.938	5.66	1.31	5.71	11.37
Pinnacle West	1.10	29.813	4.59	1.15	3.86	8.45
United Illuminating	2.88	26.625	2.08	2.94	11.04	13.12
Utilicorp United	1.76	26.625	3.51	1.82	6.84	10.35
Average	$1.67	$26.456	4.19	$1.73	6.76	10.95

Company	Current Dividend	Average Price March-May	Value Line Growth (%)	Projected Dividend (%)	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.875	1.00	1.90	7.34	8.34
CMS Energy	1.20	32.563	10.50	1.33	4.07	14.57
Commonwealth Energy	1.58	21.125	1.00	1.60	7.55	8.55
DQE	1.36	28.188	5.00	1.43	5.07	10.07
Eastern Utility Associates	1.66	17.750	1.50	1.68	9.49	10.99
GPU, Inc.	2.00	33.063	3.00	2.06	6.23	9.23
Illinova Corp.	1.24	22.938	8.50	1.35	5.87	14.37
Pinnacle West	1.10	29.813	8.00	1.19	3.98	11.98
United Illuminating	2.88	26.625	1.50	2.92	10.98	12.48
Utilicorp United	1.76	26.625	2.00	1.80	6.74	8.74
Average	$1.67	$26.456	4.20	$1.72	6.73	10.93

DCF Analysis: BBB/Baa Rated Electrics

Company	Current Dividend	Price 5/30/97	Retention Growth (%)	Projected Dividend (%)	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.625	2.60	$1.93	7.53	10.13
CMS Energy	1.20	33.625	7.87	1.29	3.85	11.72
Commonwealth Energy	1.58	21.750	5.27	1.66	7.65	12.91
DQE	1.36	28.125	4.33	1.42	5.05	9.38
Eastern Utility Associates	1.66	17.625	1.03	1.68	9.52	10.54
GPU, Inc.	2.00	35.000	4.96	2.10	6.00	10.96
Illinova Corp.	1.24	21.875	5.66	1.31	5.99	11.65
Pinnacle West	1.10	29.375	4.59	1.15	3.92	8.51
United Illuminating	2.88	28.625	2.08	2.94	10.27	12.35
Utilicorp United	1.76	27.000	3.51	1.82	6.75	10.26
Average	$1.67	$26.863	4.19	$1.73	6.65	10.84

Company	Current Dividend	Price as of 5/30/97	Value Line Growth (%)	Projected Dividend	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.625	1.00	$1.90	7.41	8.41
CMS Energy	1.20	33.625	10.50	1.33	3.94	14.44
Commonwealth Energy	1.58	21.750	1.00	1.60	7.34	8.34
DQE	1.36	28.125	5.00	1.43	5.08	10.08
Eastern Utility Associates	1.66	17.625	1.50	1.68	9.56	11.06
GPU, Inc.	2.00	35.000	3.00	2.06	5.89	8.89
Illinova Corp.	1.24	21.875	8.50	1.35	6.15	14.65
Pinnacle West	1.10	29.375	8.00	1.19	4.04	12.04
United Illuminating	2.88	28.625	1.50	2.92	10.21	11.71
Utilicorp United	1.76	27.000	2.00	1.80	6.65	8.65
Average	$1.67	$26.863	4.20	$1.72	6.63	10.83

DCF Analysis: BBB/Baa Rated Electrics

Company	Current Dividend	Average Price March-May	5-Year Earnings Growth	5 Year Dividend Growth	Average Growth	Projected Dividend	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.875	5.00	1.00	3.00	$1.97	7.63	10.63
CMS Energy	1.20	32.563	-9.50	34.50	12.50	1.09	3.34	15.84
Commonwealth Energy	1.58	21.125	6.00	1.00	3.50	1.67	7.93	11.43
DQE	1.36	28.188	8.00	5.50	6.75	1.47	5.21	11.96
GPU, Inc.	2.00	33.063	1.00	10.50	5.75	2.02	6.11	11.86
Average	$1.60	$28.163	2.10	10.50	6.30	$1.64	6.04	12.34

Company	Current Dividend	Price as of 5/30/97	5-Year Earnings Growth	5 Year Dividend Growth	Average Growth	Projected Dividend (%)	Projected Yield (%)	Projected Return on Equity (%)
Boston Edison	$1.88	$25.625	5.00	1.00	3.00	1.97	7.70	10.70
CMS Energy	1.20	33.625	-9.50	34.50	12.50	1.09	3.23	15.73
Commonwealth Energy	1.58	21.750	6.00	1.00	3.50	1.67	7.70	11.20
DQE	1.36	28.125	8.00	5.50	6.75	1.47	5.22	11.97
GPU, Inc.	2.00	35.000	1.00	10.50	5.75	2.02	5.77	11.52
Average	$1.60	$28.825	2.10	10.50	6.30	$1.64	5.93	12.23

BBB/Baa Electrics: Common Equity Ratios

	1993	1994	1995	1996	1997	1998	2000-2002
Boston Edison	37.0 %	40.4 %	41.8 %	45.1 %	48.5 %	52.0 %	58.0 %
CMS Energy	26.5	25.9	30.4	33.4	35.0	36.5	41.5
Commonwealth Energy	41.3	44.8	50.0	51.5	53.0	55.5	61.5
DQE	43.4	45.7	46.9	45.5	48.0	50.5	53.5
DTE Energy Company	43.1	43.4	44.9	46.0	48.0	48.0	53.0
Eastern Utility Associates	38.7	42.8	44.5	46.0	47.5	46.5	46.0
Entergy Corp.	42.8	43.1	44.6	42.2	41.0	42.0	44.5
GPU, Inc.	49.8	47.9	48.7	49.5	51.0	52.0	54.5
Hawaiian Electric	44.8	45.7	46.2	46.3	45.0	45.0	47.5
Illinova Corp.	36.7	38.6	43.8	45.9	48.5	51.0	57.0
Montana Power	57.5	58.1	56.8	56.2	56.5	57.5	60.0
Nevada Power	46.0	49.2	47.6	47.5	45.5	45.0	44.0
New York State E & G	46.0	46.5	50.0	51.9	54.0	55.0	58.5
Ohio Edison	39.7	39.6	43.3	44.8	48.5	52.5	63.0
Pinnacle West	35.3	38.3	40.4	43.2	44.5	47.0	52.5
Rochester G & E	45.9	46.5	47.5	50.9	53.0	54.5	57.5
Texas Utilities	40.0	41.5	35.7	38.2	40.0	42.0	45.5
United Illuminating	30.7	35.7	32.7	33.5	35.0	35.5	37.5
Utilicorp United	43.8	47.5	39.0	42.1	43.5	44.0	46.5
Average	**41.5 %**	**43.2 %**	**43.9 %**	**45.2 %**	**46.6 %**	**48.0 %**	**51.7 %**
PECO Energy Co.	**43.1 %**	**43.9 %**	**48.0 %**	**49.9 %**	**50.0 %**	**50.0 %**	**51.0 %**

Source: *Value Line*, May 23, 1997, April 11, 1997, and March 14, 1996.

BBB/Baa Electrics: Common Equity Ratios
(Companies used in DCF analysis)

	1993	1994	1995	1996	1997	1998	2000-2002
Boston Edison	37.0 %	40.4 %	41.8 %	45.1 %	48.5 %	52.0 %	58.0 %
CMS Energy	26.5	25.9	30.4	33.4	35.0	36.5	41.5
Commonwealth Energy	41.3	44.8	50.0	51.5	53.0	55.5	61.5
DQE	43.4	45.7	46.9	45.5	48.0	50.5	53.5
Eastern Utility Associates	38.7	42.8	44.5	46.0	47.5	46.5	46.0
GPU, Inc.	49.8	47.9	48.7	49.5	51.0	52.0	54.5
Illinova Corp.	36.7	38.6	43.8	45.9	48.5	51.0	57.0
Pinnacle West	35.3	38.3	40.4	43.2	44.5	47.0	52.5
United Illuminating	30.7	35.7	32.7	33.5	35.0	35.5	37.5
Utilicorp United	43.8	47.5	39.0	42.1	43.5	44.0	46.5
Average	**38.3 %**	**40.8 %**	**41.8 %**	**43.6 %**	**45.5 %**	**47.1 %**	**50.9 %**
PECO Energy Co.	**43.1 %**	**43.9 %**	**48.0 %**	**49.9 %**	**50.0 %**	**50.0 %**	**51.0 %**

Source: *Value Line,* May 23, 1997, April 11, 1997, and March 14, 1996.

BBB/Baa Electrics: Risk Indicators

	Safety Rank	Financial Strength	Beta	Price Stability	Nuclear Percent
Boston Edison	3.0	B	0.70	95	37.0 %
CMS Energy	4.0	C++	0.85	75	14.0
Commonwealth Energy	3.0	B++	0.80	95	25.0
DQE	2.0	A	0.75	100	31.0
DTE Energy Company	3.0	B+	0.80	100	9.0
Eastern Utility Associates	4.0	B	0.70	90	28.0
Entergy Corp.	4.0	C++	0.75	90	32.0
GPU, Inc.	3.0	B++	0.85	95	23.0
Hawaiian Electric	2.0	B++	0.70	100	0.0
Illinova Corp.	3.0	B	0.90	80	19.0
Montana Power	3.0	B++	0.70	100	0.0
Nevada Power	3.0	B+	0.75	100	0.0
New York State E & G	3.0	B++	0.80	90	7.0
Ohio Edison	3.0	B+	0.75	95	23.0
Pinnacle West	3.0	B	0.80	95	40.0
Rochester G & E	3.0	B+	0.65	100	50.0
Texas Utilities	3.0	B+	0.70	95	15.0
United Illuminating	4.0	C++	0.70	100	37.0
Utilicorp United	3.0	B+	0.75	95	0.0
Average	**3.1**	**B+**	**0.76**	**94**	**20.5**
PECO Energy Co.	**2.0**	**B++**	**0.85**	**90**	**49.9**

Source: *Value Line*, May 23, 1997, April 11, 1997, and March 14, 1996.

BBB/Baa Electrics: Risk Indicators

	Safety Rank	Financial Strength	Beta	Price Stability	Nuclear Percent
Boston Edison	3.0	B	0.70	95	37.0 %
CMS Energy	4.0	C++	0.85	75	14.0
Commonwealth Energy	3.0	B++	0.80	95	25.0
DQE	2.0	A	0.75	100	31.0
Eastern Utility Associates	4.0	B	0.70	90	28.0
GPU, Inc.	3.0	B++	0.85	95	23.0
Illinova Corp.	3.0	B	0.90	80	19.0
Pinnacle West	3.0	B	0.80	95	40.0
United Illuminating	4.0	C++	0.70	100	37.0
Utilicorp United	3.0	B+	0.75	95	0.0
Average	**3.2**	**B+**	**0.78**	**92**	**25.4**
PECO Energy Co.	**2.0**	**B++**	**0.85**	**90**	**49.9**

Source: *Value Line*, May 23, 1997, April 11, 1997, and March 14, 1996.

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1968	6.22 %	6.35 %	6.51 %	6.87 %
1969	7.12	7.34	7.54	7.93
1970	8.31	8.52	8.69	9.18
1971	7.72	8.00	8.16	8.63
1972	7.46	7.60	7.72	8.17
1973	7.60	7.72	7.84	8.17
1974	8.71	9.04	9.50	9.84
1975	9.03	9.44	10.09	10.96
1976	8.63	8.92	9.29	9.82
1977	8.19	8.43	8.61	9.06
1978	8.87	9.10	9.29	9.62
1979	9.87	10.23	10.49	10.97
1980	12.30	13.00	13.34	13.95
1981	14.64	15.30	15.95	16.54
1982:				
January	15.79	16.48	16.83	17.83
February	15.88	16.33	16.84	17.83
March	15.05	15.57	16.50	17.16
April	14.86	15.12	16.31	17.00
May	14.68	15.01	16.04	16.68
June	15.32	15.78	16.42	17.21
July	14.96	15.67	16.42	17.09
August	13.98	14.71	15.83	16.37
September	13.24	13.92	15.40	15.68
October	12.42	13.21	14.79	15.10
November	12.11	12.92	14.46	14.81
December	12.32	12.76	14.43	14.69
1983:				
January	12.29	12.74	14.24	14.56
February	12.48	13.02	14.26	14.61
March	12.19	12.67	13.94	14.33
April	12.00	12.43	13.61	14.07
May	12.01	12.44	13.50	14.05
June	12.23	12.64	13.64	14.16
July	12.69	12.86	13.58	14.01
August	13.04	13.18	13.57	14.21
September	12.85	13.04	13.42	14.10
October	12.66	12.88	13.25	13.95
November	12.82	12.97	13.38	14.12
December	13.00	13.14	13.52	14.23

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1984:				
January		13.02 %	13.39 %	14.05 %
February		13.04	13.41	14.05
March		13.66	13.87	14.56
April		13.93	14.16	14.82
May		14.66	14.90	15.28
June		14.90	15.09	15.50
July		14.42	14.82	15.50
August		13.67	14.43	14.79
September		13.43	14.17	14.51
October	13.00	13.38	13.80	14.17
November	12.66	13.00	13.23	13.72
December	12.49	12.76	13.11	13.46
1985:				
January	12.47	12.68	12.99	13.36
February	12.61	12.87	13.08	13.44
March	13.08	13.50	13.87	14.19
April	12.77	13.17	13.61	14.11
May	12.18	12.65	13.12	13.62
June	11.17	11.68	12.13	12.66
July	11.18	11.55	12.07	12.70
August	11.23	11.65	12.13	12.73
September	11.27	11.68	12.13	12.72
October	11.23	11.61	12.01	12.52
November	10.71	11.10	11.49	12.04
December	10.24	10.57	10.97	11.48
1986:				
January	10.14	10.44	10.79	11.24
February	9.65	9.98	10.26	10.74
March	8.75	9.16	9.48	9.91
April	8.45	8.87	9.14	9.63
May	9.07	9.38	9.59	10.02
June	9.02	9.36	9.62	10.03
July	8.66	9.05	9.37	9.69
August	8.59	9.03	9.29	9.70
September	8.91	9.28	9.52	9.96
October	8.84	9.24	9.52	9.95
November	8.59	9.01	9.28	9.69
December	8.41	8.81	9.12	9.49

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1987:				
January	8.23 %	8.62 %	8.95 %	9.27 %
February	8.29	8.69	9.00	9.24
March	8.21	8.64	8.93	9.19
April	8.83	9.15	9.38	9.85
May	9.34	9.63	9.91	10.40
June	9.37	9.61	10.02	10.46
July	9.56	9.70	10.13	10.62
August	9.92	10.05	10.45	10.90
September	10.53	10.66	11.22	11.58
October	10.92	11.11	11.34	11.91
November	10.43	10.62	10.82	11.40
December	10.64	10.78	10.98	11.55
1988:				
January	10.39	10.52	10.76	11.34
February	9.77	9.91	10.10	10.65
March	9.72	9.92	10.09	10.69
April	10.07	10.29	10.54	11.23
May	10.29	10.53	10.81	11.38
June	10.27	10.52	10.79	11.27
July	10.50	10.76	11.04	11.52
August	10.66	10.85	11.17	11.69
September	10.15	10.34	10.61	11.13
October	9.62	9.79	9.97	10.31
November	9.52	9.80	9.90	10.35
December	9.67	9.90	10.06	10.44
1989:				
January	9.72	9.89	10.08	10.38
February	9.71	9.93	10.07	10.38
March	9.87	10.05	10.23	10.50
April	9.88	10.02	10.18	10.49
May	9.60	9.79	9.99	10.29
June	9.13	9.37	9.64	9.80
July	8.98	9.23	9.50	9.64
August	9.02	9.27	9.52	9.64
September	9.10	9.35	9.58	9.70
October	9.01	9.28	9.54	9.64
November	8.92	9.25	9.51	9.64
December	8.92	9.26	9.44	9.60

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1990:				
January	9.08	9.39	9.56	9.74
February	9.35	9.59	9.76	9.96
March	9.48	9.60	9.85	10.06
April	9.60	9.81	9.92	10.13
May	9.58	9.83	10.00	10.16
June	9.38	9.60	9.80	9.96
July	9.36	9.61	9.75	9.92
August	9.54	9.78	9.92	10.12
September	9.73	9.87	10.12	10.32
October	9.66	9.77	10.05	10.28
November	9.43	9.59	9.90	10.12
December	9.18	9.42	9.73	9.96
1991:				
January	9.17	9.39	9.71	9.96
February	8.92	9.16	9.47	9.68
March	9.04	9.23	9.55	9.74
April	8.95	9.14	9.46	9.64
May	8.93	9.16	9.44	9.64
June	9.10	9.28	9.59	9.79
July	9.10	9.26	9.55	9.69
August	8.81	9.06	9.29	9.47
September	8.65	8.95	9.16	9.34
October	8.57	8.92	9.12	9.32
November	8.52	8.87	9.05	9.28
December	8.38	8.71	8.88	9.07
1992:				
January	8.22	8.63	8.84	8.98
February	8.30	8.76	8.93	9.09
March	8.39	8.82	8.97	9.16
April	8.36	8.76	8.93	9.11
May	8.32	8.69	8.87	9.01
June	8.26	8.63	8.78	8.90
July	8.12	8.45	8.57	8.69
August	8.04	8.30	8.44	8.58
September	8.04	8.28	8.40	8.54
October	8.06	8.42	8.54	8.76
November	8.11	8.51	8.63	8.86
December	8.01	8.32	8.43	8.69

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1993:				
January	7.94	8.14	8.27	8.57
February	7.75	7.92	8.04	8.31
March	7.64	7.76	7.90	8.10
April	7.50	7.64	7.81	8.11
May	7.44	7.64	7.86	8.18
June	7.37	7.54	7.75	8.05
July	7.25	7.38	7.54	7.93
August	6.94	7.07	7.25	7.59
September	6.76	6.89	7.04	7.35
October	6.75	6.89	7.03	7.27
November	7.06	7.17	7.30	7.69
December	7.06	7.18	7.34	7.73
1994:				
January	7.05	7.18	7.33	7.66
February	7.19	7.34	7.42	7.76
March	7.60	7.74	7.85	8.11
April	8.00	8.12	8.22	8.47
May	8.11	8.24	8.33	8.61
June	8.07	8.21	8.31	8.64
July	8.21	8.38	8.47	8.80
August	8.15	8.32	8.41	8.74
September	8.41	8.56	8.64	8.98
October	8.65	8.78	8.86	9.24
November	8.77	8.90	8.98	9.35
December	8.55	8.69	8.76	9.16
1995:				
January	8.53	8.66	8.73	9.15
February	8.33	8.45	8.52	8.93
March	8.18	8.29	8.37	8.78
April	8.08	8.17	8.27	8.67
May	7.17	7.80	7.91	8.30
June	7.39	7.49	7.60	8.01
July	7.51	7.60	7.70	8.11
August	7.66	7.71	7.83	8.24
September	7.42	7.48	7.62	7.98
October	7.23	7.30	7.46	7.82
November	7.13	7.22	7.43	7.81
December	6.94	7.03	7.23	7.63
1996:				
January	6.92	7.02	7.22	7.64
February	7.11	7.20	7.37	7.78
March	7.45	7.55	7.73	8.15
April	7.60	7.70	7.89	8.32
May	7.73	7.79	7.98	8.45
June	7.83	7.87	8.06	8.51
July	7.78	7.83	8.02	8.44
August	7.59	7.66	7.84	8.25
September	7.76	7.84	8.01	8.41
October	7.50	7.60	7.77	8.15
November	7.21	7.32	7.49	7.87
December	7.33	7.44	7.59	7.98

Moody's Public Utility Bond Yields

Year	Aaa	Aa	A	Baa
1997:				
January	7.53	7.68	7.77	8.18
February	7.47	7.60	7.64	8.02
March	7.70	7.84	7.87	8.26
April	7.88	8.00	8.03	8.42

Source: *Moody's Public Utility Manuals* and *Moody's Bond Record.*

PECO Energy Company: Projected Growth Rates

Report	Projected Dividends Per Share	Projected Earnings Per Share	Projected Return on Common Equity (%)	Projected Retention Rate (%)	Retention Growth Rate (%)	Value-Line Dividend Forecast
10/07/77	$1.80	$2.25	13.0 %	20.0 %	2.70 %	1.5 %
10/06/78	1.88	2.70	13.0	30.4	4.10	2.0
10/05/79	1.80	2.65	13.0	32.1	4.33	0.5
10/03/80	2.10	2.50	11.0	16.0	1.84	3.5
10/02/81	2.15	2.35	12.5	8.5	1.11	3.0
12/31/82	2.20	2.60	13.0	15.4	2.08	3.0
12/30/83	2.40	2.80	13.0	14.3	1.93	4.0
12/28/84	3.00	3.70	13.0	18.9	2.55	4.5
12/27/85	2.40	2.80	14.0	14.3	2.07	2.0
12/26/86	2.20	2.75	12.5	20.0	2.60	0.5
12/25/87	2.20	3.00	14.0	26.7	3.87	0.0
12/23/88	2.20	2.75	13.5	20.0	2.80	0.0
12/22/89	2.20	2.30	13.0	4.3	0.59	0.0
12/21/90	1.40	2.20	11.0	36.4	4.18	-7.5
12/20/91	1.90	2.70	12.5	29.6	3.85	-0.5
12/18/92	2.00	2.70	12.5	25.9	3.37	3.5
12/17/93	2.00	2.90	13.0	31.0	4.19	7.0
12/16/94	1.95	2.90	13.0	32.8	4.42	6.5
12/15/95	2.05	3.10	12.5	33.9	4.40	6.0
12/13/96	2.19	3.05	12.5	28.2	3.67	6.0

Source: *Value Line*.

Note: Retention Rate = 1 - Dividends/Earnings
Growth Rate = Retention Rate x (Return on Equity + 0.5%).
Return on equity increased by 0.5% to reflect conversion from year-end to average year basis.

PECO Energy Company: Historical DCF Analysis

Year	Price	Projected Dividend	Projected Yield	Retention Growth Rate	Expected Return
1978	$19.625	$1.81	9.21 %	2.70 %	11.91 %
1979	15.500	1.87	12.09	4.10	16.19
1980	13.750	1.88	13.66	4.33	17.99
1981	12.500	1.83	14.66	1.84	16.50
1982	13.625	1.92	14.10	1.11	15.21
1983	17.000	2.10	12.37	2.08	14.45
1984	14.375	2.16	15.03	1.93	16.96
1985	14.875	2.26	15.17	2.55	17.72
1986	17.375	2.25	12.92	2.07	14.99
1987	22.625	2.26	9.98	2.60	12.58
1988	18.500	2.29	12.35	3.87	16.22
1989	20.000	2.26	11.31	2.80	14.11
1990	23.125	2.21	9.57	0.59	10.16
1991	18.000	1.51	8.39	4.18	12.57
1992	25.875	1.27	4.92	3.85	8.77
1993	26.125	1.37	5.24	3.37	8.61
1994	30.250	1.49	4.93	4.19	9.12
1995	24.500	1.61	6.58	4.42	11.00
1996	30.125	1.72	5.72	4.40	10.12
1997	25.250	1.82	7.23	3.67	10.90

Note: price is closing price of December of previous year.
Projected dividend is declared dividend of previous year times
1 + the growth rate.

PECO Energy Company: Historical DCF Analysis

Year	Price	Projected Dividend	Projected Yield	Value Line Growth Rate	Expected Return
1978	$19.625	$1.79	9.10 %	1.50 %	10.60 %
1979	15.500	1.84	11.85	2.00	13.85
1980	13.750	1.81	13.16	0.50	13.66
1981	12.500	1.86	14.90	3.50	18.40
1982	13.625	1.96	14.36	3.00	17.36
1983	17.000	2.12	12.48	3.00	15.48
1984	14.375	2.20	15.34	4.00	19.34
1985	14.875	2.30	15.46	4.50	19.96
1986	17.375	2.24	12.92	2.00	14.92
1987	22.625	2.21	9.77	0.50	10.27
1988	18.500	2.20	11.89	0.00	11.89
1989	20.000	2.20	11.00	0.00	11.00
1990	23.125	2.20	9.51	0.00	9.51
1991	18.000	1.34	7.45	-7.50	-0.05
1992	25.875	1.22	4.71	-0.50	4.21
1993	26.125	1.37	5.25	3.50	8.75
1994	30.250	1.53	5.06	7.00	12.06
1995	24.500	1.65	6.72	6.50	13.22
1996	30.125	1.75	5.81	6.00	11.81
1997	25.250	1.87	7.39	6.00	13.39

Note: price is closing price of December of previous year.
Projected dividend is declared dividend of previous year times
1 + the growth rate.

PECO Energy Company: Historical Return Analysis

Year	Risk-Free Rate	Beta	Market Premium	Required Return
1978	7.94 %	0.70	7.80 %	13.40 %
1979	8.88	0.70	7.80	14.34
1980	10.12	0.70	8.00	15.72
1981	12.40	0.60	8.50	17.50
1982	13.45	0.60	8.30	18.43
1983	10.54	0.60	7.80	15.22
1984	11.88	0.60	8.00	16.68
1985	11.52	0.60	7.70	16.14
1986	9.54	0.65	7.60	14.48
1987	7.37	0.65	7.40	12.18
1988	9.12	0.70	7.40	14.30
1989	9.01	0.75	7.40	14.56
1990	7.90	0.75	7.50	13.53
1991	8.24	0.75	7.30	13.72
1992	7.50	0.75	7.30	12.98
1993	7.43	0.70	7.20	12.47
1994	6.17	0.70	7.20	11.21
1995	7.87	0.75	7.20	13.27
1996	6.06	0.70	7.00	10.96
1997	6.55	0.85	7.00	12.50

Source: Workpapers.

Note: Required return is equal to the risk-free rate plus beta times the market premium.

PECO Energy Company: Expected Risk Premiums, 1978-1997

		Bond Yield		Risk Premium Based on:	
Year	Expected Return on Stock	Long-term Treasury Bonds	Baa Utility Bond Rate	On Treasury Rate	On Utility Rate
1978	11.91 %	7.94 %	9.08 %	3.97 %	2.83 %
1979	16.19	8.88	10.08	7.31	6.11
1980	17.99	10.12	12.51	7.87	5.48
1981	16.50	12.40	15.29	4.10	1.21
1982	15.21	13.45	17.02	1.76	-1.81
1983	14.45	10.54	14.69	3.91	-0.24
1984	16.96	11.88	14.23	5.08	2.73
1985	17.72	11.52	13.46	6.20	4.26
1986	14.99	9.54	11.48	5.45	3.51
1987	12.58	7.37	9.49	5.21	3.09
1988	16.22	9.12	11.55	7.10	4.67
1989	14.11	9.01	10.44	5.10	3.67
1990	10.16	7.90	9.60	2.26	0.56
1991	12.57	8.24	9.96	4.33	2.61
1992	8.77	7.50	9.07	1.27	-0.30
1993	8.61	7.44	8.69	1.17	-0.08
1994	9.12	6.25	7.73	2.87	1.39
1995	11.00	7.87	9.16	3.13	1.84
1996	10.12	6.06	7.63	4.06	2.49
1997	10.90	6.55	7.98	4.35	2.92
			Average	**4.33 %**	**2.35 %**
			Average Excl. Neg. Values	**4.33 %**	**3.08 %**
			Ave. 1993-1997	**3.12 %**	**2.16 %**

Source: Expected returns from Schedule 10, page 1 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

PECO Energy Company: Expected Risk Premiums, 1978-1997

Year	Expected Return on Stock	Bond Yield: Long-term Treasury Bonds	Bond Yield: Baa Utility Bond Rate	Risk Premium Based on: On Treasury Rate	Risk Premium Based on: On Utility Rate
1978	10.60 %	7.94 %	9.08 %	2.66 %	1.52 %
1979	13.85	8.88	10.08	4.97	3.77
1980	13.66	10.12	12.51	3.54	1.15
1981	18.40	12.40	15.29	6.00	3.11
1982	17.36	13.45	17.02	3.91	0.34
1983	15.48	10.54	14.69	4.94	0.79
1984	19.34	11.88	14.23	7.46	5.11
1985	19.96	11.52	13.46	8.44	6.50
1986	14.92	9.54	11.48	5.38	3.44
1987	10.27	7.37	9.49	2.90	0.78
1988	11.89	9.12	11.55	2.77	0.34
1989	11.00	9.01	10.44	1.99	0.56
1990	9.51	7.90	9.60	1.61	-0.09
1991	-0.05	8.24	9.96	-8.29	-10.01
1992	4.21	7.50	9.07	-3.29	-4.86
1993	8.75	7.44	8.69	1.31	0.06
1994	12.06	6.25	7.73	5.81	4.33
1995	13.22	7.87	9.16	5.35	4.06
1996	11.81	6.06	7.63	5.75	4.18
1997	13.39	6.55	7.98	6.84	5.41
			Average	**3.50 %**	**1.52 %**
			Average Excl. Neg. Values	**4.54 %**	**2.67 %**
			Ave. 1993-1997	**5.01 %**	**3.61 %**

Source: Expected returns from Schedule 10, page 2 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

Note:

PECO Energy Company: Expected Risk Premiums, 1978-1997

		Bond Yield		Risk Premium Based on:	
Year	Expected Return on Stock	Long-term Treasury Bonds	Baa Utility Bond Rate	On Treasury Rate	On Utility Rate
1978	13.40 %	7.94 %	9.08 %	5.46 %	4.32 %
1979	14.34	8.88	10.08	5.46	4.26
1980	15.72	10.12	12.51	5.60	3.21
1981	17.50	12.40	15.29	5.10	2.21
1982	18.43	13.45	17.02	4.98	1.41
1983	15.22	10.54	14.69	4.68	0.53
1984	16.68	11.88	14.23	4.80	2.45
1985	16.14	11.52	13.46	4.62	2.68
1986	14.48	9.54	11.48	4.94	3.00
1987	12.18	7.37	9.49	4.81	2.69
1988	14.30	9.12	11.55	5.18	2.75
1989	14.56	9.01	10.44	5.55	4.12
1990	13.53	7.90	9.60	5.63	3.93
1991	13.72	8.24	9.96	5.48	3.76
1992	12.98	7.50	9.07	5.48	3.91
1993	12.47	7.44	8.69	5.03	3.78
1994	11.21	6.25	7.73	4.96	3.48
1995	13.27	7.87	9.16	5.40	4.11
1996	10.96	6.06	7.63	4.90	3.33
1997	12.50	6.55	7.98	5.95	4.52
			Average	**5.20 %**	**3.22 %**
			Ave. 1993-1997	**5.25 %**	**3.84 %**

Source: Expected returns from Schedule 10, page 3 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

Moody's 24 Electrics: Growth Rates

Year	Beta	Projected DPS	Projected EPS	Projected ROE	Retention Rate (%)	Retention Growth Rate (%)	Value Line Projected Dividend Growth	Value Line Projected Earnings Growth
1977	0.75	$2.33	$3.67	12.7	36.5	4.82	5.5	6.6
1978	0.74	2.39	3.64	12.6	34.3	4.50	5.6	6.2
1979	0.71	2.53	3.75	12.6	32.5	4.26	5.6	5.9
1980	0.63	2.47	3.54	12.6	30.2	3.96	5.0	5.0
1981	0.65	2.76	3.80	13.4	27.4	3.80	5.5	5.6
1982	0.64	2.86	3.89	14.1	26.5	3.87	6.2	6.6
1983	0.66	2.77	3.76	13.6	26.3	3.71	5.3	5.4
1984	0.65	2.79	3.77	13.9	26.0	3.74	5.0	4.5
1985	0.67	2.73	3.74	14.0	27.0	3.92	4.8	4.0
1986	0.68	2.56	3.61	14.0	29.1	4.22	3.9	3.2
1987	0.73	2.34	3.29	13.4	28.9	4.01	2.4	2.0
1988	0.70	2.36	3.31	13.4	28.7	3.99	1.9	2.0
1989	0.71	2.41	3.24	13.4	25.6	3.56	2.9	2.4
1990	0.70	2.49	3.25	13.2	23.4	3.20	2.8	3.2
1991	0.66	2.45	3.40	13.2	27.9	3.83	2.9	4.3
1992	0.65	2.13	2.83	12.5	24.7	3.22	2.6	3.4
1993	0.65	1.90	2.50	12.0	24.0	3.00	1.6	2.6
1994	0.70	1.89	2.55	12.2	25.9	3.29	1.1	3.3
1995	0.72	1.89	2.61	12.0	27.6	3.45	2.4	3.7
1996	0.75	1.74	2.52	11.7	31.0	3.78	2.3	4.1

Source: *Value Line* .

Note: Retention Rate = 1 - Dividends/Earnings
Growth Rate = Retention Rate x (Return on Equity).

Moody's 24 Electrics: Historical Return Analysis

Year	Price	Projected Dividend	Projected Yield	Retention Growth Rate	Expected Return
1978	$68.19	$5.95	8.73 %	4.82 %	13.55 %
1979	59.75	6.25	10.46	4.50	14.96
1980	56.41	6.61	11.72	4.26	15.98
1981	54.42	6.93	12.74	3.96	16.70
1982	57.20	7.43	12.99	3.80	16.79
1983	70.26	7.94	11.29	3.87	15.16
1984	72.03	8.30	11.52	3.71	15.23
1985	80.16	8.68	10.83	3.74	14.57
1986	94.98	9.05	9.53	3.92	13.45
1987	113.66	9.35	8.22	4.22	12.44
1988	94.24	9.49	10.07	4.01	14.08
1989	100.94	9.06	8.97	3.99	12.96
1990	122.52	9.17	7.48	3.56	11.04
1991	117.77	9.04	7.68	3.20	10.88
1992	144.02	9.37	6.50	3.83	10.33
1993	141.06	9.10	6.45	3.22	9.67
1994	146.70	9.31	6.35	3.00	9.35
1995	115.50	9.31	8.06	3.29	11.35
1996	141.80	9.37	6.61	3.45	10.06
1997	135.88	9.40	6.92	3.78	10.70

Source: *Moody's Public Utility Manual, 1994* and Schedule 12.

Note: Price is average December price of previous year.
Projected dividend is dividend of previous year times 1 plus the growth rate.
Price for 1997 is preliminary.

Moody's 24 Electrics: Historical Return Analysis

Year	Price	Projected Dividend	Projected Yield	Value Line Growth Rate	Expected Return
1978	$68.19	$5.99	8.79 %	5.5 %	14.29 %
1979	59.75	6.31	10.57	5.6	16.17
1980	56.41	6.70	11.87	5.6	17.47
1981	54.42	7.00	12.87	5.0	17.87
1982	57.20	7.55	13.21	5.5	18.71
1983	70.26	8.11	11.55	6.2	17.75
1984	72.03	8.42	11.70	5.3	17.00
1985	80.16	8.79	10.96	5.0	15.96
1986	94.98	9.13	9.61	4.8	14.41
1987	113.66	9.32	8.20	3.9	12.10
1988	94.24	9.34	9.91	2.4	12.31
1989	100.94	8.88	8.79	1.9	10.69
1990	122.52	9.11	7.43	2.9	10.33
1991	117.77	9.01	7.65	2.8	10.45
1992	144.02	9.28	6.44	2.9	9.34
1993	141.06	9.05	6.42	2.6	9.02
1994	146.70	9.18	6.26	1.6	7.86
1995	115.00	9.11	7.89	1.1	8.99
1996	141.80	9.28	6.54	2.4	8.94
1997	135.88	9.27	6.82	2.3	9.12

Source: *Moody's Public Utility Manual, 1994* and Schedule 12.

Note: Price is average December price of previous year.
Projected dividend is dividend of previous year
times 1 plus the growth rate.
Price for 1997 is preliminary.

Moody's Electrics: Historical Return Analysis

Year	Risk-Free Rate	Beta	Market Premium	Required Return
1978	7.94 %	0.75	7.80 %	13.79 %
1979	8.88	0.74	7.80	14.65
1980	10.12	0.71	8.00	15.80
1981	12.40	0.63	8.50	17.76
1982	13.45	0.65	8.30	18.85
1983	10.54	0.64	7.80	15.53
1984	11.88	0.66	8.00	17.16
1985	11.52	0.65	7.70	16.53
1986	9.54	0.67	7.60	14.63
1987	7.37	0.68	7.40	12.40
1988	9.12	0.73	7.40	14.52
1989	9.01	0.70	7.40	14.19
1990	7.90	0.71	7.50	13.23
1991	8.24	0.70	7.30	13.35
1992	7.50	0.66	7.30	12.32
1993	7.43	0.65	7.20	12.11
1994	6.17	0.65	7.20	10.85
1995	7.87	0.70	7.20	12.91
1996	6.06	0.72	7.00	11.10
1997	6.55	0.73	7.00	11.66

Source: Workpapers.

Note: Required return is equal to the risk-free rate plus beta times the market premium.

Moody's 24 Electrics: Expected Risk Premiums, 1978-1997

		Bond Yield		Risk Premium Based on:	
Year	Expected Return on Stock	Long-term Treasury Bonds	Single-A Utility Bond Rate	On Treasury Rate	On Utility Rate
1978	13.55 %	7.94 %	8.64 %	5.61 %	4.91 %
1979	14.96	8.88	9.70	6.08	5.26
1980	15.98	10.12	11.79	5.86	4.19
1981	16.70	12.40	14.63	4.30	2.07
1982	16.79	13.45	16.29	3.34	0.50
1983	15.16	10.54	14.43	4.62	0.73
1984	15.23	11.88	13.52	3.35	1.71
1985	14.57	11.52	13.11	3.05	1.46
1986	13.45	9.54	10.97	3.91	2.48
1987	12.44	7.37	9.12	5.07	3.32
1988	14.08	9.12	10.98	4.96	3.10
1989	12.96	9.01	10.06	3.95	2.90
1990	11.04	7.90	9.44	3.14	1.60
1991	10.88	8.24	9.73	2.64	1.15
1992	10.33	7.50	8.88	2.83	1.45
1993	9.67	7.44	8.43	2.23	1.24
1994	9.35	6.25	7.34	3.10	2.01
1995	11.35	7.87	8.76	3.48	2.59
1996	10.06	6.06	7.23	4.00	2.83
1997	10.70	6.55	7.59	4.15	3.11
			Average	**3.98 %**	**2.43 %**

Source: Expected returns from Schedule 13, page 1 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

Moody's 24 Electrics: Expected Risk Premiums, 1978-1997

Year	Expected Return on Stock	Bond Yield: Long-term Treasury Bonds	Bond Yield: Single-A Utility Bond Rate	Risk Premium Based on: On Treasury Rate	Risk Premium Based on: On Utility Rate
1978	14.29 %	7.94 %	8.64 %	6.35 %	5.65 %
1979	16.17	8.88	9.70	7.29	6.47
1980	17.47	10.12	11.79	7.35	5.68
1981	17.87	12.40	14.63	5.47	3.24
1982	18.71	13.45	16.29	5.26	2.42
1983	17.75	10.54	14.43	7.21	3.32
1984	17.00	11.88	13.52	5.12	3.48
1985	15.96	11.52	13.11	4.44	2.85
1986	14.41	9.54	10.97	4.87	3.44
1987	12.10	7.37	9.12	4.73	2.98
1988	12.31	9.12	10.98	3.19	1.33
1989	10.69	9.01	10.06	1.68	0.63
1990	10.33	7.90	9.44	2.43	0.89
1991	10.45	8.24	9.73	2.21	0.72
1992	9.34	7.50	8.88	1.84	0.46
1993	9.02	7.44	8.43	1.58	0.59
1994	7.86	6.25	7.34	1.61	0.52
1995	8.99	7.87	8.76	1.12	0.23
1996	8.94	6.06	7.23	2.88	1.71
1997	9.12	6.55	7.59	2.57	1.53
			Average	**3.96 %**	**2.41 %**

Source: Expected returns from Schedule 13, page 2 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

Moody's 24 Electrics: Expected Risk Premiums, 1978-1997

		Bond Yield		Risk Premium Based on:	
Year	Expected Return on Stock	Long-term Treasury Bonds	Single-A Utility Bond Rate	On Treasury Rate	On Utility Rate
1978	13.79 %	7.94 %	8.64 %	5.85 %	5.15 %
1979	14.65	8.88	9.70	5.77	4.95
1980	15.80	10.12	11.79	5.68	4.01
1981	17.76	12.40	14.63	5.36	3.13
1982	18.85	13.45	16.29	5.40	2.56
1983	15.53	10.54	14.43	4.99	1.10
1984	17.16	11.88	13.52	5.28	3.64
1985	16.53	11.52	13.11	5.01	3.42
1986	14.63	9.54	10.97	5.09	3.66
1987	12.40	7.37	9.12	5.03	3.28
1988	14.52	9.12	10.98	5.40	3.54
1989	14.19	9.01	10.06	5.18	4.13
1990	13.23	7.90	9.44	5.33	3.79
1991	13.35	8.24	9.73	5.11	3.62
1992	12.32	7.50	8.88	4.82	3.44
1993	12.11	7.44	8.43	4.67	3.68
1994	10.85	6.25	7.34	4.60	3.51
1995	12.91	7.87	8.76	5.04	4.15
1996	11.10	6.06	7.23	5.04	3.87
1997	11.66	6.55	7.59	5.11	4.07
			Average	**5.19 %**	**3.64 %**

Source: Expected returns from Schedule 13, page 3 of 3.
30 year Government Bond Yields, *Federal Reserve Bulletin;*
Utility Bond Yields, *Moody's Public Utility Manuals* and
Bond Survey.

Exhibit___(JBL-1)
Schedule 15

Moody's 24 Electrics: Risk Indicators

Company	Beta	Safety Rank	1997 Equity Ratio	Price Stability	S&P Bond Rating	Inde	Moody's Bond Rating	Index
Baltimore G & E	0.85	2.0	48.0 %	95	A+	4	A1	4
Boston Edison	0.70	3.0	48.5	95	BBB	8	Baa2	8
Carolina P & L	0.85	2.0	51.5	95	A	5	A2	5
Centerior Energy	0.70	4.0	34.5	75	BB	11	Ba2	11
Central Hudson G & E	0.65	3.0	53.5	100	A-	6	A3	6
Central Maine Power	0.80	4.0	45.5	80	BB+	10	Baa3	9
CINergy Corp.	0.90	2.0	51.5	95	A-	6	A3	6
Consolidated Edison	0.80	1.0	55.0	95	A+	4	Aa3	3
Delmarva Power & Light	0.70	2.0	47.0	100	A	5	A2	5
DPL	0.75	1.0	55.5	100	AA-	3	Aa3	3
DTE Energy	0.80	3.0	48.0	100	BBB+	7	Baa2	8
Edison International	0.70	2.0	44.5	90	A+	4	A2	5
Florida Progress	0.65	2.0	51.5	100	AA-	3	Aa3	3
Houston Industries	0.80	3.0	52.5	90	A-	6	A3	6
Idaho Power	0.70	2.0	45.5	100	A+	4	A2	5
IPALCO Enterprises	0.75	2.0	31.5	100	AA-	3	Aa2	2
Northeast Utilities	0.80	5.0	33.5	65	BBB-	9	Ba1	10
OGE Energy Corp.	0.80	2.0	53.5	95	AA-	3	A1	4
PG&E Corp.	0.70	3.0	49.0	90	A	5	A2	5
PP&L Resources	0.75	2.0	48.5	95	A-	6	A3	6
PECO Energy Co,	0.85	2.0	50.0	90	BBB+	7	Baa1	7
Pub. Serv. Co. of Colorado	0.75	3.0	49.5	100	A-	6	A3	6
TECO Energy	0.70	2.0	55.5	100	AA	2	Aa2	2
Unicom Corporation	0.80	3.0	49.5	75	BBB	8	Baa3	9
Average	**0.76**	**2.5**	**48.0 %**	**93**	**A-**	**6**	**A2**	**6**
PECO Energy Co,	0.85	2.0	50.0	90	BBB+	7	Baa1	7

Source: *Value Line*, March 14, 1997; April 11, 1997; May 23, 1997; *Moody's Bond Record*, May 1997; *S&P Bond Guide*, June 1997.

BBB/Baa Electrics: Value Line and S&P Betas

Company:	Value Line Beta	S&P Beta
Boston Edison	0.70	0.58
CMS Energy	0.85	0.16
Commonwealth Energy	0.80	0.60
DQE	0.75	0.61
DTE Energy Company	0.80	0.68
Eastern Utility Associates	0.70	0.78
Entergy Corp.	0.75	0.76
GPU, Inc.	0.85	0.60
Hawaiian Electric	0.70	0.49
Illinova	0.90	0.81
Montana Power	0.70	0.22
Nevada Power	0.75	0.12
New York State E & G	0.80	0.68
Ohio Edison	0.75	0.71
Pinnacle West	0.80	0.55
Rochester G & E	0.65	0.57
Texas Utilities	0.70	0.22
United Illuminating	0.70	0.29
Utilicorp United	0.75	0.55
Average	**0.76**	**0.53**
PECO	**0.85**	**0.52**

Source: *Value Line*, May 23, 1997, March 14, 1997 and April 11, 1997;
Standard & Poor's, *Stock Reports, NYSE*, February 1997.

BBB/Baa Electrics: Value Line and S&P Betas

Company:	Value Line Beta	S&P Beta
Boston Edison	0.70	0.58
CMS Energy	0.85	0.16
Commonwealth Energy	0.80	0.60
DQE	0.75	0.61
Eastern Utility Associates	0.70	0.78
GPU, Inc.	0.85	0.60
Illinova	0.90	0.81
Pinnacle West	0.80	0.55
United Illuminating	0.70	0.29
Utilicorp United	0.75	0.55
Average	**0.78**	**0.55**
PECO	**0.85**	**0.52**

Source: *Value Line*, May 23, 1997, March 14, 1997 and April 11, 1997;
Standard & Poor's, *Stock Reports, NYSE*, February 1997.

BBB/Baa Electrics: Value Line and S&P Betas

(BRENNAN'S COMPARABLES)

Company:	Value Line Beta	S&P Beta
American Electric Power Co.	0.70	0.47
Boston Edison Company	0.70	0.58
CINergy Corporation	0.90	0.70
DQE, Inc.	0.75	0.61
DTE Energy Company	0.80	0.68
Energy Corp.	0.75	0.76
GPU, Inc.	0.85	0.60
Illinova	0.90	0.81
PP&L Resources	0.75	0.56
Average	**0.79**	**0.64**
PECO	**0.85**	**0.52**

Source: *Value Line*, May 23, 1997, March 14, 1997 and April 11, 1997;
Standard & Poor's, *Stock Reports*, *NYSE*, May 1997.

THE VALUE LINE Investment Survey®

Page 1
Summary & Index

Exhibit___(JBL-1)
Schedule 17

June 13, 1997

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

16.4

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
15.8	4.8	16.9

The Median of
ESTIMATED YIELDS
(next 12 months) of all dividend paying stocks under review

1.9%

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
2.1%	7.8%	2.3%

The Estimated Median
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

45%

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
45%	234%	40%

*Estimated medians as published in *The Value Line Investment Survey* on the dates shown.

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's edition.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LII, No. 40.
Published weekly by VALUE LINE PUBLISHING, INC. 220 East 42nd Street, New York, N.Y. 10017-5891

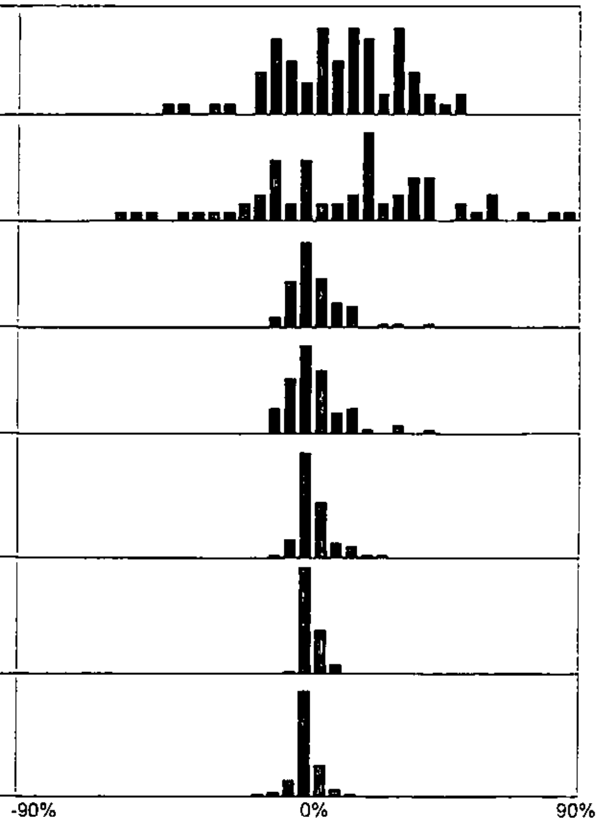
Exhibit___(JBL-1)
Schedule 18

Table 2-1

Basic Series: Summary Statistics of Annual Total Returns

From 1926 to 1995

Series	Geometric Mean	Arithemetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.5%	12.5%	20.4%	
Small Company Stocks	12.5	17.7	34.4	*
Long-Term Corporate Bonds	5.7	6.0	8.7	
Long-Term Government	5.2	5.5	9.2	
Intermediate-Term Government	5.3	5.4	5.8	
U.S. Treasury Bills	3.7	3.8	3.3	
Inflation	3.1	3.2	4.6	



*The 1933 Small Company Stock Total Return was 142.9 percent.

BBB/Baa Electrics: Value Line Projected Returns

Company:	1997	1998	2000-2002
Boston Edison	12.0 %	11.0 %	10.0 %
CMS Energy	13.0	13.0	13.5
Commonwealth Energy	13.5	13.0	12.0
DQE	12.5	12.5	11.0
DTE Energy Company	11.5	11.5	11.5
Eastern Utility Associates	10.0	9.5	9.5
Entergy Corp.	9.5	10.0	10.5
GPU, Inc.	12.5	12.0	11.5
Hawaiian Electric	11.5	11.5	12.5
Illinova	11.5	11.5	11.0
Montana Power	11.5	11.5	11.0
Nevada Power	10.0	10.0	10.5
New York State E & G	9.5	9.0	8.5
Ohio Edison	12.5	12.5	12.5
Pinnacle West	10.5	10.0	9.5
Rochester G & E	11.0	10.0	9.5
Texas Utilities	12.0	12.0	10.5
United Illuminating	10.5	10.5	10.5
Utilicorp United	10.0	10.5	11.5
Average	**11.3 %**	**11.1 %**	**10.9 %**
PECO	**10.5 %**	**10.5 %**	**10.5 %**

Source: *Value Line*, May 23, 1997, March 14, 1997 and April 11, 1997.

BBB/Baa Electrics: Value Line Projected Returns
(Companies used in DCF analysis)

Company:	1997	1998	2000-2002
Boston Edison	12.0 %	11.0 %	10.0 %
CMS Energy	13.0	13.0	13.5
Commonwealth Energy	13.5	13.0	12.0
DQE	12.5	12.5	11.0
Eastern Utility Associates	10.0	9.5	9.5
GPU, Inc.	12.5	12.0	11.5
Illinova	11.5	11.5	11.0
Pinnacle West	10.5	10.0	9.5
United Illuminating	10.5	10.5	10.5
Utilicorp United	10.0	10.5	11.5
Average	**11.6 %**	**11.4 %**	**11.0 %**
PECO	**10.5 %**	**10.5 %**	**10.5 %**

Source: *Value Line*, May 23, 1997, March 14, 1997 and April 11, 1997.

Weighted Average Cost of Capital

Based on December 31, 1996 PECO Energy Company's
Capital Structure:

Component	Capital Structure	Cost Rate	Weighted Cost	After-Tax Weighted Cost
Long-term Debt	43.10 %	8.47 %	3.65 %	2.14 %
MIPS Debt	3.30	9.21	0.30	0.18
Preferred Stock	3.00	7.70	0.23	0.23
Common Equity	50.60	11.40	5.77	5.77
Total	**100.00 %**		**9.95 %**	**8.31 %**

Note: Assumes an effective income tax rate of 41.493%.
Weighted cost of long-term debt adjusted by dividing cost rate by (1-.41493).

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KJR

June 19, 1997

Paul R. Bonney, Esq.
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VIA FEDERAL EXPRESS

Re: Pennsylvania Public Utility Commission v. PECO Energy Company - Application of PECO Energy Company for Approval of its Restructuring Plan under Section 2806 of the Public Utility Code; Docket No. R-00973953

Dear Paul:

Enclosed is the response of Philadelphia Area Industrial Energy Users Group ("PAIEUG") to PECO Energy Company's Interrogatories and Document Requests - Set II, to Interrogatory 17.

Very truly yours,

McNEES, WALLACE & NURICK

By Derrick P. Williamson

Derrick P. Williamson

DPW/jb

c: Certificate of Service
James J. McNulty, Prothonotary (Certificate of Service only)

PROTHONOTARY'S OFFICE
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DOCUMENT
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing responses to interrogatories and document requests of PECO Energy Company - Set II of the Philadelphia Area Industrial Energy Users Group upon the participants listed below in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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Derrick P. Williamson

Dated this 19th day of June, 1997, in Harrisburg, Pennsylvania.

CERTIFICATE OF SERVICE

I hereby certify that on June 19, 1997, I caused a true and correct copy of New Energy Venture, Inc.'s Direct Testimony and Interrogatory Responses NEV-I-1 to 22 to be served in the manner indicated, upon the following counsel at the addressed noted below:

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JADworetzky

Joseph A. Dworetzky

Dated: June 19, 1997

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KJR

June 19, 1997

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<u>VIA FEDERAL EXPRESS</u>

James J. McNulty, Acting Prothonotary
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Re: PECO Restructuring
<u>Docket No. R-00973953</u>

Dear Mr. McNulty:

I enclose for filing an original and three copies of the Direct Testimony of New Energy Venture, Inc.'s expert witnesses. I have also enclosed a Certificate of Service with respect to New Energy Venture, Inc.'s responses to PECO's discovery requests NEV-I-1 through 22.

Sincerely,

Joseph A. Dworetzky

JAD:kbs
encl.
cc: Certificate of Service (w/encl.)

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117

NEV STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of PECO Energy Company for	:	
Approval of its Restructuring Plan Under	:	Docket No. R-00973953
Section 2806 of the Public Utility Code	:	

DIRECT TESTIMONY
OF
DAVID MAGNUS BOONIN

Regarding Generation Rate, CTC's, Unbundling of
Certain Bundled Tarriffs and Billing Issues

Q. Please state your name, title and business address.

A. My name is David Magnus Boonin. I am President of New Energy Ventures, Mid-Atlantic. My business address is 1845 Walnut Street, Suite 2525, Philadelphia, PA 19103.

Q. Please describe New Energy Ventures (NEV).

A. NEV is the organizer and manager of a buyers' alliance for retail energy. Our business is saving our members money on their energy bills. In this proceeding and elsewhere, we work for our members and potential members. We have offices in California, Boston, New York and Philadelphia. We are a certified FERC Power Marketer and are a registered provider of retail electricity in California. NEV has a license application pending in Rhode Island and has applied for a membership in the New England Power Pool. We are currently preparing our license application to submit in Pennsylvania.

Q. Please describe your education and experience.

A. Since graduation from The Wharton School in 1973, I have spent almost my entire career in the fields of utility planning, management and policy. A copy of my resume is attached as NEV/DMB Exhibit #1. Some of my positions prior to joining NEV including serving as Chief Economist for the Pennsylvania Public Utility Commission, Commissioner and Executive Director of the Philadelphia Gas Commission and Supervisor of Economic and Energy Forecasting for a major electric utility. I also headed my own consulting practice. Among the issues I addressed on behalf of my clients was the issue of the restructuring of the utility industry. I have had extensive experience in designing adjustment clauses under section 1307 of the 66 Pa.C.S.A. I have also presented or had published numerous papers and have testified before regulatory and legislative bodies on utility and regulatory issues.

Q. What is the purpose of your testimony?

A. The main purpose of my testimony is to present an approach for the unbundling of the cost of generation which is consistent with Act and allows for the development of a competitive market for electricity. I have also identified tariffs and riders where PECO still needs to provide for unbundled generation. In addition, I will also address the billing issue of the definition of the term customer in the deregulated market.

UNBUNDLED RATE FOR GENERATION

Q. Please summarize your approach to establish an unbundled price for generation.

A. I propose that the unbundled price for generation is to be determined by the market rather than some pre-established estimate of market prices. This is necessary in order to make choice a reality for retail customers while treating all affected parties equitably. In this newly competitive world, generators will be afforded the opportunity to sell their power on a power exchange. The price for generation should be determined by the market-clearing price of the power exchange, adjusted for the costs of retail delivery. To make this comply with rate cap, I also recommend that the unbundled charge for electricity and the CTC always be kept in balance so that the total of the two never varies.

Q. You mentioned that the unbundling methodology should comply with the law. What does the statute state?

A. Section 2802 (14) of the statute states in part:

> "The generation of electricity will no longer be regulated as a public utility function."

Section 2804(3) of the statute states in part:

> "The Commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution."

Section 2808(E)(3) of the statute states:

> "If a customer contracts for electricity and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or the Commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall fully recover all reasonable costs." (emphasis added)

Q. Why is Section 2808(E)(3) important?

A. Section 2808(E)(3) determines the price the electric distribution utility (EDU) may charge for generation to any user other than those who have chosen an alternative generation supplier. This section sets forth that the EDU (or someone else designated by the Commission) shall provide this service at "prevailing market prices" and be fully compensated. As the price of generation is otherwise deregulated by the Act and is to be unbundled, it is precisely this language which sets the unbundled price of generation which may be charged by the EDU.

Q. You also mentioned that the unbundled price of generation should be based on certain market principles. Please explain.

A. In practice, the price of generation varies from hour to hour across the year. Fixed prices established through regulation, even those with demand charges and/or time-of-use pricing will only reflect the actual price of generation by happenstance. This is the fundamental practice under the existing regulatory paradigm. In the new competitive environment, electricity is being turned into a commodity whose price shall vary depending on market conditions. Therefor, appropriate unbundled price of generation should also vary with the market and not be fixed.

Q. Why is a variable versus a fixed price of generation more appropriate?

A. For the Commission to estimate and establish a fixed price for generation in an unbundled, full service tariff it must make and lock in numerous assumptions. Generally, when estimating a price, "normal" assumptions are made about weather, fuel, prices, economic conditions, supply availability, etc. These assumptions are for extended periods. There is almost no possibility that these normal estimated costs will produce a price at prevailing market rates at every time let alone at most times.

In contrast, a variable price can change with market conditions and frees the Commission from the impossible task of accurately predicting the prevailing market price of generation. This approach is also consistent with the intent of the legislation which is to deregulate the price of generation, not to reestablish a regulated price of generation on a different concept than historical rate base regulation.

Q. How is PECO proposing to set the unbundled price of electricity?

A. For each tariff, which PECO is proposing to offer unbundled service, PECO has set a fixed price for the generation component, sometimes varying by load factor. This fixed price is based upon the numerous assumptions PECO has made at the time of its filing and is levelized over several years.

Q. Why has PECO taken this approach?

A. According to PECO,(see NEV/DMB Exhibit 2) setting a fixed rate is necessary to assure that its full service tariff (i.e., service including generation) complies with the rate cap.

Q. Does this comply with the Act?

A. As stated above, the generation rate charged by an EDU is to be "at prevailing market prices to serve that customer." There is no other guidance in the Act to establish an unbundled generation rate. What PECO proposes cannot be expected to be prevailing market prices. It is a leveled and averaged price estimate. This is not consistent with concept of prevailing market price that will be determined every hour by the market. Although this approach may address differences in load factor for some classes of customers, it does not individually allocate the price responsibility for each customer as required by the statute's language. A load factor approach fails to consider what time of day or even day of the week either the peak or the usage occurs. It is at best a crude estimate of actual prevailing prices for individual, especially larger customers. Most importantly, PECO's prices are mere estimates of prices and are therefore not prevailing market prices.

Q. Do you believe that an order of the Commission approving a fixed generation price would be lawful?

A. No. As noted above, such an order would violate the Act.

Q. Has PECO recently estimated the price of generation in another proceeding?

A. Yes. PECO provided estimates of generation prices in its QRO filing (Docket Nos. R-00973897-C001 and C002), made two months prior to this restructuring filing.

Q. How do generation costs in the QRO filing compare to the restructuring filing?

A. In the two months between these two filings, PECO changed its estimate of the price for generation as indicated in NEV/DMB Exhibit #3. The figures given in $/mWh are copied from PECO Exhibit JFB-1 from its QRO filing (designated as old) and from its restructuring filing (designated as new). Exhibit 3 is only presented to demonstrate the futility of estimating the prevailing market price. I am not endorsing any of the figures used for any other purpose. PECO, seemingly recognized the difficulty of forecasting generation market price and retained three consulting firms to review this issue.

I have compared the results presented in these two PECO exhibits, submitted about ten weeks apart and have identified a great number of discrepancies and changes in such a short time span. When comparing the same consultant's figures at these two points in time, I noticed significant changes in their estimates. The most notable occurs with the estimates presented of EDS where approximately a 10% change was made (based upon the median). It is unimportant why these consultants found it necessary to change their estimates so significantly over such a short time period. The consultant may have changed his estimate based upon a myriad of necessary underlying assumptions. Whether the forecast was changed up or down is unimportant; the important fact is that each consultant found it necessary to change its forecast. This indicates how unreliable these estimates are as true predictors of the prevailing market rate at any given time. It also vividly illustrates why the Commission should not endeavor to set a fixed rate.

Additionally, NEV/DMB Exhibit #3 indicates that even at the same point in time, three consultants all working for the same client cannot agree on the generation market price. These discrepancies at the same point in time are another indication of the futility of establishing fixed prices for the unbundled price of generation.

Q. Is the 10% level of change you pointed out significant?

A. Yes. NEV's entire business is based upon beating alternative prices available to our Buyers Alliance members. The margins will be very thin on the purchasing of energy. A 10% change (such as the one discussed above) in an established price can mean the difference between a viable choice and no choice or chance for savings by end-users of electricity.

Q. Earlier you stated that in addition to complying with the law, a system for unbundling the price of generation must also address the realities of the marketplace. Does PECO's proposal for unbundling meet this goal?

A. Again PECO's proposal fails. By establishing a fixed price the Commission may:

- over-reward alternative suppliers if a fixed generation rate in excess of the prevailing market price is established. This may penalize EDUs and less informed customers who fall prey to suppliers who misrepresent the market choices based upon an artificially high tariffed rate;

- ♦ cripple the market if a fixed generation rate below the prevailing market price is set, making choice virtually meaningless.. When the customer is faced with a choice of paying a tariffed rate below the prevailing market price for generation, there becomes little incentive to shift from the consumer's perspective and little incentive for alternative providers to enter the market. This situation will result in no real choice being offered or exercised. Also, it should not be over-looked if the tariffed rate for generation is established too low, the CTC will likely be set too high;

- ♦ confuse customers who are being offered variable, market determined rates by alternative suppliers and a fixed rate by the EDU. Many customers do not need to know what their price for generation is going to be now and into the future as offered by a fixed rate. Rather they want an opportunity to shop for less expensive options. It is difficult for a customer to compare a fixed price offering in a tariff to a market-based price from a competitive supplier;

- ♦ establishes an unleveled playing field as the utility fixed rate is being offered without the additional cots of price hedges that a competitive supplier would have to procure to offer a similar service. Market power may also be skewed by the use of a levelized price where the market price is below the levelized price in the earlier years when the EDU's market power is still the greatest and giving the EDU a price advantage after its market power has a chance to be diminished by competitors; and

- ♦ create unintended cross subsidies between individual customers as fixed prices cannot accurately track differences in usage patterns.

In short, a fixed price as a proxy for prevailing market prices is the antithesis of what competition and choice are all about. PECO's proposal will not get the Commission away from being the regulator of the price of generation. In fact, the Commission establishes itself squarely in the role as the ultimate interference with an open market for generation. Only a variable approach to the bundled price for generation meets the needs of a competitive market.

Q. What is your proposal for the unbundling of generation in the EDU's tariff?

A. I propose inserting the following language in each tariff for individual classes of customer:

> "The unbundled rate for generation shall be established by the power exchange market clearing bid price for generation, fully adjusted for ancillary services necessary to convert wholesale generation into reliable, deliverable retail power at market determined or FERC approved prices which may be required by the independent system operator (ISO), including but not limited to, capacity, spinning reserves, load balancing and as further adjusted for losses associated with the voltage level of delivery and location."

This language would be further enhanced after the final establishment of a power exchange (PX) and/or independent system operator (ISO) and their establishment of final governing rules. As the establishment of an ISO and PX is necessary for retail competition to function, waiting to enhance this language should not in and of itself cause significant delays.

This language establishes the basis for determining the prevailing market price for retail generation at any point in time.

To understand this approach it is necessary to understand several concepts. First that power exchange establishes the wholesale price for energy by establishing a market price for electricity based on wholesale bids. Second, there are services, such as load balancing, spinning reserves, etc. which have costs, which are necessary to convert this wholesale energy into retail electricity. Third, losses associated with the transmission and distribution of electricity may cause the retail price for power to vary depending on the level of voltage delivery. Fourth, at certain times of the year, even within an EDU's service territory, locational price differences may occur, depending on physical limitations and/or FERC pricing decisions.

Q. Please explain why the power exchange price establishes the wholesale price for electricity.

A. The PX will continually solicit bids from wholesalers to meet current demands. The highest price bid used during a period (probably hourly) will set the prevailing wholesale market price for energy at that time. The process of matching supply and demand will be repeated continually during the day with a new wholesale market prevailing rate established (probably hourly). This bid process will replace the current economic dispatch system currently used by many utilities and power pools. It allows all willing suppliers to bid for the right to supply the demand that exists, excluding what has been met by bilateral contracts. There may be exceptions for plants that are dispatched for reasons other than price (e.g. system balancing). These exceptions will be known and can be treated like other ancillary services needed to convert wholesale service into retail service.

Q. Please explain why and how these services need to be adjusted to reflect reliable, deliverable retail electricity.

A. The supply and demand of electricity are subject to many stochastic events. Power plants are forced off-line. Customers turn electricity consuming equipment on and off unexpectantly and randomly. Because of this, it is not enough to use the wholesale PX price as the total power exchange price. It is also necessary to include costs associated with converting that energy into reliable retail electricity. The ISO shall determine rules of what ancillary services a supplier must provide. These services may include but are not limited to: capacity, spinning reserve and load balancing. These services are the types that are generally necessary to convert wholesale power into reliable electricity. These services will either be priced at a set price by the ISO and FERC or through the market (my preferred approach).

Q. Please discuss the adjustments that are necessary due to voltage differences.

A. Power delivered at declining voltages experience greater losses. An adjustment factor should be applied to each voltage delivery level to reflect these differences.

Q. Please discuss the adjustments that are necessary due to the location of the customer.

A. Sometimes, due to transmission limitations, power prices within a power exchange may differ at different locations. If the ISO identifies such limitations and establishes the need to have different pricing in different regions, then individual prevailing market clearing prices may need to be established for certain sub-regions at certain times.

Q. Why is this adjusted power exchange price an accurate proxy for prevailing market prices?

A. This is the way goods and services in the market are usually priced. The power exchange adjusted for retail delivery starts with a prevailing wholesale market price and adds the costs necessary to convert it to the retail service.

Q. Under your proposal, how often will the prevailing market price change?

A. It will change as often as the components discussed above cause a change. Practically, I see the prevailing market price changing hourly, much as today's power pool price (or system lambda) changes today.

Q. Given that the prevailing market price may be changing hourly, what type of metering will be necessary?

A. That will be up to the individual supplier and the ISO rules of load balancing. In general, I anticipate that hourly meters will be necessary for larger loads, regardless of whether the generation supplier is the EDU or another supplier. Small loads, such as residential and small commercial customers may be able to be metered as currently done, if the ISO permits the use of a standard load curve(s) for load balancing purposes.

Q. How do you anticipate customers being billed?

A. Each individual customer with hourly meters would be billed based upon the full prevailing retail market price for each kilowatt consumed in that hour. Demand billing and ratchets should become unnecessary following this approach for generation.

Capacity charges would be charged during the hour that the customer imposed the need. Small customers without hourly meters who have an acknowledged and approved load shape would be billed based upon the their kWh usage spread over the load shape, using the prevailing market prices at the time. Customers who do not have approved load shapes and do not have hourly meters would be charged for unallocated imbalances, as reflected for their reliance on the ISO rather than their own supplies. This creates de facto hourly pricing.

Q. Do these load shapes need to be determined at this time?

A. No. I believe this would be premature. The Commission to the ISO should recommend them after the ISO indicates a willingness to address load imbalance responsibilities based upon load shapes for some subset of customers.

Q. Earlier you stated that PECO's stated reason for proposing to use a fixed price is to comply with the rate cap. Please discuss the relevant rate cap provisions that must be met.

A. Section 2804 (4) discusses the rate cap. It basically states that the fully rebundled prices must not exceed the total price prior to unbundling. In subsection (4)(III) a cap of the pre-competitive bundled generation charge is placed on the generation charge plus the CTC and ITC.

Q. Given the variable nature of your proposed approach to unbundling generation, how will you have your approach comply with the rate cap?

A. I propose keeping the total of the unbundled price of generation and the generation related portion of the CTC constant. If the prevailing market price increases so does the unbundled charge for generation with an equal decrease to the generation portion of the CTC.

Q. Why is this appropriate?

A. Under PECO's and most other approaches determining stranded costs; there is a relationship between the prevailing market price for generation and the competitive transition charge. All else being equal, if one were to assume an increase in the value of generation because the market price of generation increased, then the stranded costs would decrease by the same amount. Likewise, if the market price of generation were to decrease, the value of the generation would decrease and stranded costs would increase.

Stranded costs are the core of the calculation of the Competitive Transition Charge (CTC). At a particular point in time (eliminating discounting and levelization) there is a one to one relationship between a change in the value of generation and an opposite but equal change in stranded costs.

Q. In general, how would this work?

A. Because of this one to one relationship, it is recommended that in establishing the unbundled rates for generation and CTC that the Commission follow the following protocol.

- Determine stranded cost, the CTC and ITC for each rate class as appropriate.

- Stranded costs, the CTC and ITC should be split between generation and non-generation related costs.

- Explicitly determine the related underlying assumed market price for generation associated with the generation portion of the CTC for each rate class. The price of generation could be levelized, but it is recommended that it be desegregated at least by year.

- The EDU would compare the average weighted prevailing market price for generation for each customer class for the billing period with the underlying assumed market price for generation.

- The generation related portion of the CTC would then be adjusted so that the total of the adjusted CTC and the prevailing market price for the period would always be equal to the base CTC and underlying assumed price of generation.

This approach is consistent with section 2804(8)(II), which joins the CTC, ITC and the unbundled price of generation.

Q. Please explain why and how you are splitting the CTC.

A. The Act at Section 2808 discusses generation related transition costs separately from other transition costs. Following this lead, I recommend that the Commission split the CTC into two categories, generation and non-generation. This allows for the generation portion of the CTC to be used as offsets to variation in the prevailing market price as discussed above. This charge should be set only on a kWh basis. Hourly allocations of generation costs should negate the need for demand charges and ratchets. I do not have an opinion at this time on the rate design for the non-generation portion of the CTC.

Q. Would you please provide a simple example of how your proposal would work?

A. Yes. Assume for purpose of illustration that the base generation related CTC established by the Commission is 1.5 cents/kWh and the associated estimated market price/value of generation is 2.9 cents per kilowatt-hour for a total of 4.4 cents. Assume also that in a given month the actual prevailing market price is 2.7 cents. This is 0.2/kWh cents less than the estimated market price that is the basis for determining the CTC. The CTC would therefore be increased by the same amount for bills rendered for that period or to 1.2 cents per kilowatt-hour. Under either case the combined total will still be 4.4 cents/kWh.

If the opposite were true and the prevailing market price were to exceed the estimated market value of generation, then the CTC would be decreased.

This self balancing process assures that the generation charges are always in compliance with the rate cap provisions of the Act.

Q. Have you considered how the Commission would go about reconciling the ITC and CTC consistent with sections 2808(F) and 2812(B)(5) of the Act, given your variable methodology?

A. Yes.

Q. Why is it necessary and appropriate for the Commission to establish a reconciliation methodology at this time?

A. The Commission in its April 10, 1997 order on periodic adjustment of the CTC and the ITC stated that "only during the course of the evidentiary hearings can such matters as the appropriate CTC/ITC calculation and reconciliation methodology be determined as well as the appropriate format, content and necessary supporting information associated with the annual CTC reconciliation's and periodic ITC adjustments."

Q. Please summarize your reconciliation methodology.

A. I propose a reconciliation method which individually reconciles the Competitive Transition Costs associated with generation and non-generation related costs. Non-generation costs would only be reconciled based on changes in absolute levels of recovery caused by variations between forecasted and actual sales. Generation related costs would also be adjusted for variations in sales but only after an adjustment is made to the required level of amortization to reflect changes in the prevailing market price. I have also proposed, as a general rule, deferring adjustments for over or undercollections to the end of the transition period.

Q. Have you provided a more detailed description of your proposed reconciliation methodology?

A. Yes. It is attached as NEV/DMB Exhibit #4.

Q. In your proposal, does it matter whether the sales are billed directly by PECO or whether PECO provided the generation service?

A. No. All customers in a given rate class should pay the same CTC rate(s).

Q. How does this work with a utility like PECO who is trying to recover its CTC partially on an energy and partially on demand basis?

A. Non generation related costs could still be recovered in a fashion similar to PECO's proposal. As I stated earlier, I have not yet developed an opinion in the appropriate rate design for this item, nor is it germane to my proposal. All generation related charges would be recovered on a kWh basis. Actual or imputed load shapes would assign actual prevailing rates to each customer. Demand ratchets would be eliminated for these portions of these services as would cross subsidization for generation. Customers would pay only for the load the actually placed on the system.

Q. Would the CTC change for all customers or only those receiving full services from the EDU?

A. The CTC would change for all customers.

Q. Why should the CTC change for all customers based upon prevailing market prices for generation?

A. The CTC is a charged being imposed on customers regardless of whether they stay with the EDU or seek energy services form an alternative supplier. The CTC should be the same for similar customers who are served by the utility at the prevailing market rate or by an alternative provider at a market-determined rate.

Q. Is there anything else you would like to note relating to the rate cap?

A. Yes. It should be noted that PECO's proposed unbundled tariffs comply with the rate cap while allowing for 100% recovery of PECO's estimate of $6.8 billion in stranded costs. If the Commission were to find any or all of these costs to be inappropriate, room would be freed under the rate cap. However, the approach I propose for dealing with the realities of a fluctuating prevailing market price for generation and the price cap does not rely upon there being room under the rate cap.

Q. Is your approach consistent with the statute and Commission orders and regulations?

A. A discussed in more detail above, yes.

Q. Can this approach be used for any utility.

A. Yes.

Q. Will people know the price of electricity before they consume it.

A. Yes. Customers electing to stay with the EDU for full service would know the price of generation before it is consumed although there may be shifting between the subparts of the CTC and generation.

Q. Does the proposed approach guarantee the recovery of allowed stranded costs?

A. Yes as annually adjusted to reflect actual market conditions. It is, therefore, a more accurate approach than one which is based upon an estimate of market prices.

Q. How would securitization work under your proposal?

A. I recommend that in order to meet the revenue guarantees associated with securitization that the Commission only allow to be recovered through the ITC costs which are either not dependent on changing market conditions and/or extremely conservative estimates of stranded costs which are influenced by generation. It may be possible however to use unexpected revenues from a higher than expected prevailing market price to support securitized stranded costs. If this is done, the Commission could securitize even a liberal estimate of generation related stranded costs.

Q. You have developed a detailed approach for unbundling. How should the final tariffs be developed?

A. I recommend that the Commission direct PECO to submit tariffs consistent with this approach and with the Commission's findings. A CTC (which could be split between generation and non-generation) will need to be provided by PECO as compliance filing with the Commission's final order. The Commission should explicitly state for each class of customer the assumed prevailing market price(s) for generation used in developing its stranded cost findings so that the adjustment mechanism I propose can be followed. A good first step would be to have PECO complete the table I have laid out in my Exhibit #4.

TARIFFS AND RIDERS WHICH ARE NOT UNBUNDLED

Q. Are there other deficiencies to PECO's proposal to unbundle generation which you would like to address?

A. Yes. In Mr. Sundmiers's testimonies (see PECO Statement #13 pages 9 -14) he excludes a series of tariffs from unbundling.

Q. What tariffs and riders that have not been unbundled have you identified as being improper?

A. PECO has not unbundled Rate SL-P, Rate SL-S, the Off-Peak Rider, the Curtailment HT rider the Emergency Energy Conservation Rider, The Employment and Economic Recovery Rider, the Large Interruptible Load Rider, the Interruptible Rider and the Incremental Process Rider.

Q. Why do you believe unbundling to be appropriate for these tariffs and riders?

A. To begin with, the Act requires that all rates be unbundled. PECO rationalizes its omission to unbundle each of these tariffs, but I do not find the arguments compelling.

Rate SL-P is not unbundled because of a "special agreement with the City" (WFS page 9 line 6). This special agreement is not forever and should not be used as a rationale not to complete the unbundling of this service at this time. Unbundling will not impact the total cost of service provided to the City under the special agreement. Also unbundling of all tariffs will provide information which customers can use to protect themselves against cross subsidies.

Rate SL-S is not unbundled because the "major cost of providing this service is lighting equipment and its maintenance" (WFS page 9, line11). The statute does not say to only unbundle tariffs where generation is a major component. This rationale must be dismissed.

The Off-Peak Rider is not unbundled because "in addition to being frozen, the Off-Peak rider is currently only available to customers whose sole source of supply is PECO" (WKS page 11, line 10). When this rider was developed it may have only been available to customers whose supply was solely PECO, but the law has changed. PECO should correct this omission.

The Curtailment Rider should be modified to be available to anyone who eases the burden on the system, not just those whose generation supplier is PECO Energy.

The Emergency Energy Conservation Rider should likewise be amended to apply to any customer who agrees to curtail usage when requirements dictate.

The Employment and Economic Recovery Rider was designed in part to use all of PECO's underutilized system more effectively, not just PECO's generation and should be unbundled accordingly.

The Large Interruptible Load Rider again is not unbundled because of some rationale about PECO being the exclusive provider. This is just what the Act changes and LILR tariffs should be unbundled.

The Incremental Process Rider also needs to be unbundled such that the customer can gain these advantages regardless of the source of generation.

BILLING AND THE DEFINITION OF A CUSTOMER

Q. Please summarize your testimony in this area.

A. Many customers have service on multiple meters throughout an EDU's service territory. These customers are currently discriminated against when compared to customers with similar loads served through a single meter. I propose that alternative generation providers be permitted to treat these customers as a single service for purposes of billing for transmission and CTC related charges.

Q. Why did you exclude generation from your earlier response?

A. The price of generation is deregulated and the EDU already has the right to issue a customer a bill for its generation services on a consolidated basis. No Commission action is required.

Q. Why did you exclude distribution charges?

A. This is a conservative proposal. Customers with multiple meters may impose a cost on the system that is different than a similar load from a single location associated with the distribution of the service. It is therefore recommended that these specific charges be billed as they are currently.

Q. How are transmission and CTC different from the distribution charges?

A. Transmission and CTC related charges should not change with the number of installations or meters but with the load placed on the system.

Q. Why does defining a customer by a meter discriminate against someone who receives service at multiple meters?

A. I will answer that question with an example. Assume that there is a customer with a single meter and a load of 2 MW. Assume also that there is someone else with three meters, all on the same tariff as the first customer, whose coincidental load totals to 2 MW but whose non-coincidental load is 2.5 MW. This second customer places the same type of non-distribution related load on the system but is being charged more than the first customer. All of these customers are on the same rate schedule and all have the same coincidental peak, but the multi-site customer is being irrationally discriminated against.

Q. In your example, you stated that all of the customers were on the same rate schedule. Would you make that a pre-condition of your bill consolidation proposal?

A. Yes. For administrative ease, if for no other reason, this consolidation should only be for customers of record who have multiple meters on the same rate tariff.

Q. How does this issue fit into this debate on *competition*?

A. Without competition this would not be as germane. Competition brings with it innovation. More and more customers will be metered such that hourly loads can be determined, a necessary request for consolidated billing. Competition also challenges the necessity of demand based billing, particularly if customers are paying for the burden they place upon the system virtually on an hourly basis. Competition also highlights the importance of electric prices in economic competitiveness. It is no longer acceptable to shrug when the type of blatant discrimination is pointed out and say that's they best we can do. Yesterday's good enough is no longer adequate.

Q. Specifically, what is your proposal?

A. My proposal is:

1. as testified by others, alternative generation providers should be allowed to issue bills for all parts of the electric service, including those charged by the EDU;
2. that an alternative generation provider be allowed to consolidate bills for customers with multiple meters within a single rate tariff;

3. that the consolidated bill will not have any impact on the distribution charge, with the exception of unbundled services for metering, billing, collections and information which shall be competitive; and

4. that only through this modification can the Commission prevent undue competition from occurring between customers with identical loads on the same rate tariff.

Q. Does this conclude your testimony at this time?

A. Yes.

EDUCATION
Brown University, M.A. in Economics, 1976
Wharton School, University of Pennsylvania, B.S. in Economics, 1973

EXPERIENCE
New Energy Ventures, Inc., Philadelphia Pennsylvanaia
PRESIDENT, MID-ATLANTIC DIVISION, 1997 - Present
Manage NEV's Mid-Atlantic operations.

Consulting
PRESIDENT, THE BOONIN GROUP,/SENIOR ADVISOR, HAGLER BAILLY CONSULTING, 1992 - 1997
Provide strategic, policy and technical advice to utilities and others dealing with utility matters. Clients and assignments are diverse ranging from industries including: electric, gas, water and transportation and issues including competition, rates, restructuring, regulatory policy, etc.

City of Philadelphia, Philadelphia, Pennsylvania
EXECUTIVE DIRECTOR, PHILADELPHIA GAS COMMISSION, 1991 - 1994
Managed the Commission's technical and administrative staffs. Provided policy and strategic advice to the Commissioners. Interfaced with the public including: government officials, the press, interest groups, etc.

COMMISSIONER, PHILADELPHIA GAS COMMISSION, 1988 - 1991
Regulated largest gas utility in the State and largest municipal gas utility in the nation. Performed detailed budgetary and management review and oversight.

DIRECTOR OF UTILITY AND REGULATORY AFFAIRS, 1988 - 1991
Directed City's activities addressing utility and regulatory issues including the City as a large user, the City as a provider of utility services and the quality of the City's economic and physical environment. Scope of issues spanned fixed and transportation utilities as well as the insurance industry. Worked with regulators, utilities, interest groups and legislators.

DIRECTOR OF INTERGOVERNMENTAL AFFAIRS, Office of the Mayor, 1985 - 1988
Directed the City's legislative and administrative efforts with federal, state and local government, including the activities of lobbyists and Philadelphia's Washington Office. Addressed financial, economic and utility problems facing the City.

United Illuminating Company, New Haven, Connecticut
SUPERVISOR, ENERGY DEMAND AND ECONOMIC FORECASTS, 1983 - 1985
Corporate economist for a major electric utility. Managed department responsible for forecasting the utility's energy sales and peak demand. Developed energy resource strategies.

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
CHIEF ECONOMIST, 1979 - 1983
Managed the Economics Division. Developed policy recommendations, performed research and/or testified on regulatory, energy, economic, financial, rate and environmental issues.

CHIEF OF THE ENERGY IMPACT ANALYSIS SECTION, 1978-1979
Managed interdisciplinary staff and projects concerning fixed utilities and energy. Developed and assessed regulations, rate structures and economic incentives.

ECONOMIST, CHAIRMAN'S STAFF, 1976 - 1978
Economic advisor to the Chairman of the Commission. Reviewed each rate case as well as other cases and offered specific recommendations on all facets of the case.

United Engineers and Constructors, Inc., Philadelphia, Pennsylvania
ECONOMIST, NUCLEAR TECHNICAL STAFF, 1973 -1975
Analyzed issues relating to the costs/benefits, safety and licensing of power plants.

SELECTED PROFESSIONAL ACTIVITIES

* Commissioner, Philadelphia Planning Commission (1990-1991)
* Member,Private Sector Advisory Panel on Infrastructure Financing, Senate Budget Committee (1986)
* Board Member, Energy Coordinating Agency (1988-Present)
* Energy, Environment and Natural Resources Policy Committee; National League of Cities (1990-1991)
* Community and Economic Development Committee; Pennsylvania League of Cities (1989-1991)
* Served on numerous committees and task forces, including: Electric Utility Efficiency Task Force, Pennsylvania Utility Advisory Committee, Statistical Research Committee - ECNE, Taxi Advisory Committee, Utility Consumers Council, *EPRI* and *NEPLAN* Committees.

PERSONAL

* American Jewish Congress - Board Member
* *B'nai Brith Anti-Defamation League - National Leadership Award 1991*
* Central High School Board Alumni Association - Board of Directors
* Boy Scouts of America - Assistant Scout Master, Eagle Scout
* Born May 18, 1952, Philadelphia, Pennsylvania; Married

Allegheny I-5 Question:

To the extent that PECO's total charges (e.g., the actual market clearing price of energy, CTC and transmission/distribution charges) would exceed the rate cap, is it PECO's intent to charge its full CTC in all such circumstances during the CTC recovery period? If not, please explain.

Allegheny I-5 Answer:

PECO's proposed total charges (which do not include the actual market clearing price) are designed not to exceed the rate cap. Therefore, PECO does intend to charge its full CTC during the recovery period.

Responsible Witness: W. F. Sundermeir

Allegheny I-6 Question:

If PECO intends to charge the levelized rates reflected in Mr. Sundermeir's Exhibit WFS-1, please identify any statutory provisions supporting PECO's determination to charge customers a generation rate below the market price and justify why such a rate is appropriate.

Allegheny I-6 Answer:

PECO's intent is not to charge a generation rate below the market price, it is to charge a levelized market price such as those reflected in Exhibit WFS-1. The determination of what the actual market price will be at a given time is not within PECO's control. The determination to charge customers a levelized generation rate is supported by the "Rate Cap" as stated in Section 2804 (4)(I)(A) of the Customer Choice Act: "The total charges of an electric distribution utility for service to any customer who purchases generation from that utility shall not exceed the total charges that have been approved by the Commission for such services as of the effective date of this chapter...". By adding a fluctuating actual market price to a combination of a levelized distribution, transmission and CTC charge, PECO would possibly exceed the rates allowed under the Rate Cap provision stated above and this is certainly not PECO's intent. As stated in response to Allegheny-I-5, PECO's proposed total charges are designed not to exceed the rate cap.

Responsible Witness: W. F. Sundermeir

COMPARISON OF PECO'S PROJECTIONS FOR MARKET PRICES OF GENERATION

Year	eds old	eds new	% change	phb old	phb new	% change	icf old	icf new	% change	old phb v eds	old phb v icf	old icf v eds	new phb v eds	new phb v icf	new icf v eds
1999	*29.2*	*28.4*	*-2.7%*	*24.2*	*24.5*	*1.2%*	*27.70*	*28.10*	1.4%	*82.9%*	*87.4%*	94.9%	*86.3%*	87.2%	98.9%
2000	31.2	31.5	1.0%	27.5	27.8	1.1%	29.90	31.30	4.7%	88.1%	92.0%	95.8%	88.3%	88.8%	99.4%
2001	32.6	36.6	12.3%	33.6	32.2	-4.2%	32.40	35.00	8.0%	103.1%	103.7%	99.4%	88.0%	92.0%	95.6%
2002	34.1	38.2	12.0%	35.0	33.9	-3.1%	36.60	36.40	-0.5%	102.6%	95.6%	107.3%	88.7%	93.1%	95.3%
2003	35.8	39.9	11.5%	36.5	35.7	-2.2%	36.70	37.50	2.2%	102.0%	99.5%	102.5%	89.5%	95.2%	94.0%
2004	37.7	41.7	10.6%	38.0	37.6	-1.1%	39.20	38.90	-0.8%	100.8%	96.9%	104.0%	90.2%	96.7%	93.3%
2005	40.0	43.4	8.5%	39.6	39.3	-0.8%	41.00	41.40	1.0%	99.0%	96.6%	102.5%	90.6%	94.9%	95.4%
2006	*41.1*	*44.8*	*9.0%*	*41.1*	*41.1*	*0.0%*	*43.10*	*43.30*	*0.5%*	*100.0%*	*95.4%*	*104.9%*	*91.7%*	*94.9%*	96.7%
2007	43.2	46.6	7.9%	42.8	43.0	0.5%	44.90	45.00	0.2%	99.1%	95.3%	103.9%	92.3%	95.6%	96.6%
2008	44.0	48.2	9.5%	44.4	44.9	1.1%	47.00	47.00	0.0%	100.9%	94.5%	106.8%	93.2%	95.5%	97.5%
2009	45.2	50.1	10.8%	46.2	47.0	1.7%	48.90	48.70	-0.4%	102.2%	94.5%	108.2%	93.8%	96.5%	97.2%
2010	46.7	52.1	11.6%	48.0	49.0	2.1%	51.20	50.60	-1.2%	102.8%	93.8%	109.6%	94.0%	96.8%	97.1%
2011	48.1	54.1	12.5%	48.8	51.1	4.7%	53.50	51.10	-4.5%	101.5%	91.2%	111.2%	94.5%	100.0%	94.5%
2012	50.2	55.4	10.4%	50.8	53.3	4.9%	55.60	53.00	-4.7%	101.2%	91.4%	110.8%	96.2%	100.6%	95.7%
2013	*52.5*	*57.3*	*9.1%*	*52.8*	*55.6*	5.3%	*57.80*	*55.00*	*-4.8%*	*100.6%*	*91.3%*	*110.1%*	*97.0%*	*101.1%*	96.0%
2014	55.1	60.4	9.6%	55.4	58.3	5.2%	60.70	57.50	-5.3%	100.5%	91.3%	110.2%	96.5%	101.4%	95.2%
2015	56.8	62.2	9.5%	55.6	59.7	7.4%	61.90	58.40	-5.7%	97.9%	89.8%	109.0%	96.0%	102.2%	93.9%

NEV/DMB #3
1 of 1

RECONCILIATION OF THE CTC

The Commission finds that the base stranded cost recoverable through the Competitive Transition Charge (CTC) is $____________. Of this amount $________________ is not generation related and $_______________ is generation related.

The generation related portion is based upon, in part, estimated levelized value of generation of $0.0xxx cents per kWh.

The base Competitive Transition Charge is as set forth in each individual rate schedule. The CTC has been divided into non-generation and generation related components.

The CTC is designed to produce the listed amortization schedule for stranded costs, divided into non-generation and generation related costs.

COMPETITIVE TRANSITION COSTS BASE ANNUAL AMORTIZATION SCHEDULE				
Year	Total to be Amortized	Non-generation Related Costs	Generation Related Costs	Projected Sales
1999				
2000				
2001				
2002				
2003				
2004				
2005				

The CTC shall be reconciled annually consistent with section 1307(e) of 66 Pa. C.S.A. Reconciliation of over or under collections shall be collected by extending or shortening the CTC period, except as otherwise ordered by the Commission.

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Non-generation related CTC shall be adjusted based upon the following formula.

$Nongen_{.act} - Nongen_{.amort} = E_{nongen}$

where:

$Nongen_{.act}$ is the actual amount collected from all classes of customers during a year for non-generation related competitive transition charges;

$Nongen_{.amort}$ is the amortization schedule for the same year for non-generation related competitive transition charges as shown in the schedule; and

E_{nongen} is the over or under collections associated with non-generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

Note: this methodology only produces over or undercollections of non-generation related CTC when projected sales vary from actual sales.

There shall be two types of adjustments made for generation related CTC:

an adjustment to the amortization schedule based upon differences between the base generation related CTC and the CTC based on the actual market value generation, and

an adjustment for the anticipated versus actual level of collection (similar to the adjustment for non-generation related CTC).

The first step is to adjust the amortization schedule for the year being reconciled. This shall be done according to the following formula.

$(CTC_{market} \times SALES_{projected}) - (CTC_{base} \times SALES_{projected}) = E_{amort}$

where:

CTC_{market} is the adjusted CTC charged to each class of customer to reflect the change in the value of generation from that used in the calculation of the base CTC. It is determined for each class of customer by the formula:

$$CTC_{market} = CTC_{base} - (GENVALUE_{actual} - GENVALUE_{base})$$

where:

$GENVALUE_{actual}$ is weighted average of the actual prevailing market price for generation as established in each tariff; and

$GENVALUE_{base}$ is the estimated weighted average market price of generation used to in establishing stranded costs and the related base CTC, embedded in the tariff for each class of service.

CTC_{base} is the weighted average CTC based upon projected market prices and value of generation and included in the tariff for each class of service.

$SALES_{projected}$ is the number of kWh used to determine the amortization schedule as listed in the table above.

E_{amort} is the adjustment that is made to the amortization schedule for generation related CTC to reflect the change in market conditions. This changes the total dollars which need to be collected through this portion of the CTC over the transition period.

Weighting is based upon projected kWh sales for each class of service.

After the amortization schedule has been adjusted for the prevailing market price for the period, the second step is to adjust the generation related CTC for actual level of collection according to the following formula.

$Gen_{act} - Gen_{amort.adj} = E_{gen}$

where:

Gen_{act} is the actual amount collected from all classes of customers during a year for generation related competitive transition charges;

$Gen_{amort.adj}$ is the amortization schedule adjusted for the change in the market value of generation for the same year for generation related competitive transition charges as shown in the schedule and as adjusted; and

E_{gen} is the over or under collections associated with generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

NEV STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code	:	Docket No. R-00973953

DIRECT TESTIMONY
OF
NANCY I. DAY

Regarding Billing

QI Please state your name and business address.

AI My name is Nancy I. Day and my business address is as follows:

New Energy Ventures, Inc.
1000 Wilshire Boulevard, Suite 500
Los Angeles, CA 90017.

Q2 By whom are your employed and in what capacity?

A2 I am employed by New Energy Ventures, Inc. My job title is Vice President, Customer Services. I am responsible for defining the critical elements necessary to delivery competitive services to energy customers. In addition I am responsible for the legislative and regulatory advocacy of policies and programs essential to build viable competitive energy markets. My resume is attached as Exhibit NEV/NID #1.

Q3 Please describe your background and experience in the energy services industry.

A3 From 1968 to 1995 I was employed by Southern California Gas Company, the nation's largest natural gas distribution utility. From 1990-94 I served as Vice President of Regulatory Affairs. In that capacity I was the senior officer responsible for developing and executing regulatory strategies. I directed a staff of 30 professionals responsible for obtaining the required regulatory authorizations needed to run the business. I led the company's regulatory initiatives related to the transition to competitive choice for the provision of natural gas.

Q4 What is the nature of your testimony in this proceeding?

A4 My testimony focuses on the role unbundling of distribution services plays in the formation of competitive energy markets. I will address the essential components of distribution service unbundling. Finally, I will discuss my experience in the deregulation of California's natural gas and electric services industries to the extent they pertain to the issue of service unbundling.

Q5 Why is distribution service unbundling an essential element of the restructured energy services market?

A5 The simple answer is profitability. Without the unbundling and competitive provision of distribution services new market entrants will eventually be starved out of the market. This will be the inevitable result when the margins on the sale of electricity are too small to support the new market entrant's service delivery overheads. In contrast, the utility service providers' costs for provision of these overheads are imbedded in the utility's distribution revenue requirement and the utility does not have to compete for the delivery of those services. This creates an improper and unfair advantage for the utility and if corrective action is not taken will result in the demise of customers' competitive alternatives.

Over time, the primary benefits from electric industry restructuring will come, not from commodity cost savings, but from changes at the customer's premises. The provision of these value added services is key to establishing sustainable business relationships with customers. Moreover, the types of services customers want and are willing to pay for are highly competitive, not monopoly services.

For example, from a wide array of competitive options customers want to select those options whose value equals or exceeds their cost. If the utilities package of services do not meet the customers needs yet the costs remain bundled the customer must pay twice, once to the utility for valueless services and once to the energy service provider for the customized package of customer-selected services.

A simple example illustrates this point. Customer "Big" has many facilities located throughout the State. Historically this customer was served by 3 different utilities all of whom billed for each meter served. Each utilities' billing format and rate characteristics were different. Customer "Big" employed a small staff to aggregate the utility charges by business unit and review them for accuracy. As part of his new bundle of energy services Customer "Big" wants an aggregated electricity bill, including both utility and energy service charges, subtotaled by business unit and provided on-line through the internet. Why should this customer have to pay for the utilities to continue to send him useless information?

Q6 What services and costs should be unbundled?

A6 My recommendations are based on the cost and service format applied to California utilities and I recommend the Pennsylvania Commission evaluate these recommendations in the context of Pennsylvania's facts.

The cost elements that represent a minimum level of unbundling are:

1. Meters and meter reading
2. Billing and collections (including data processing costs)
3. Customer Service
4. Commodity Procurement, scheduling, balancing, risk management and sales.
5. Uncollectible Expense
6. Working Cash Allowance

Q7 What did the California Public Utilities Commission decide with respect to unbundling distribution services?

A7 In D. 97-05-037 the California Public Utilities Commission ordered the following:

Billing

1. Customers may choose from three billing options as follows: utility and the new Energy Service Provider (ESP) provide separate bills, the utility consolidates bills for itself and the ESP, or the ESP consolidates bills for itself and the utility.

2. ESPs who provide consolidated billing for the utility are responsible for payment of the billed amounts to the utility regardless of their ability to collect from their customers.

3. Utilities may impose reasonable creditworthiness requirements on ESPs who provide consolidated billing. These requirements are to be the same as those required of a similarly sized and situated customer.

4. ESPs who provide consolidated billing must describe the utilities' charges on their bills in a manner consistent with the bill reporting standards the CPUC sets for the utilities.

Meters and Meter Reading

1. Utilities who wish to employ Automated Meter Reading (AMR) (or any other type of advanced metering system) technology throughout their service territories may do so subject to the following conditions:

- utility customers will have the choice of deciding whether they want to use the real-time metering capability offered by the technology

- only customers electing to use the real-time pricing capability of AMR will be required to pay for the costs of that technology

- utility shareholders will be at risk for the full recovery of the technology's costs

- at the same time, the utility installing AMR would not be required to lower its revenue requirement associated with metering as a results of cost savings achieved from adopting the technology

- balances risk and reward between ratepayers and shareholders

- a utility deciding to adopt AMR would provide the Commission with a deployment plan showing how the technology would be geographically deployed and on what timetable.

2. ESPs may install their own meters and must agree to share the metered information with the utility. The ESP and the utility will enter into a service agreement specifying the nature of the information to be collected, the means for sharing data, and a reasonable approach for ensuring that the metering equipment is installed, calibrated and maintained properly, The Commission will establish minimum standards governing open architecture for meters and communication.

   - large customers may use ESP meters beginning 1-1-98

- small customers (less than 20 kilowatts) may use ESP meters beginning 1-1-99.

The Commission delayed installation of ESP meters for small customers by one year to "encourage a more studied movement through the various steps that must precede such a new commercial offering." (D. 97-05-039, pg. 17.)

Cost Separation

The Commission concluded that customers should not pay for costs that are not incurred and directed that utilities separately identify the net cost savings resulting from a customer's election to receive certain revenue cycle services from another service provider and to reduce distribution charges where appropriate.

Other Services

In addition to billing, metering and meter reading, the Commission found there are other costs related to customer service inquiries and uncollectibles that are "logically related to revenue cycle services." (D. 9705-039, pg. 18.) The Commission directed the utilities to identify the net customer service inquiry savings to be used to reduce customer charges in those situations where an energy supplier chooses to handle customer service inquiries. In response to the concerns expressed by one party, the Commission directed all parties to evaluate whether a universal uncollectibles pool should be established to motivate ESPs to serve customers who pose a higher credit risk.

Q8 The issue of distribution service unbundling was hotly contested in California. Why do you think the California Public Utilities Commission ordered unbundling?

A8 In the California Commission's decision on unbundling (D. 97-05-039) Commissioner Jesse J. Knight, Jr. wrote as follows:

"Unbundling bottleneck facilities has played a key component in regulation of the telecommunications industry and was an important part of the Commission's efforts to ensure that full and fair markets properly develop. Access to bottleneck facilities and the unbundling of potentially competitive services allows greater innovation in services, a more customer focused marketplace and an important check on the ability of the dominant provider to leverage market power into adjacent markets. This decision takes this important lesson and applies it to the revenue cycle services of the electric industry."

Based on my active involvement in this proceeding and knowledge of the natural gas market in California I believe the Commission recognized that without revenue cycle service unbundling the competitive market in California would not flourish.

In 1991 when the California Commission opened the natural gas market to competitive choice they failed to unbundle services for residential and commercial customers (so-called Core Customers). As a result, the core natural gas aggregation program never achieved significant market penetration and over the years participation of marketers has declined from a high of 12 to 3 or 4 remaining today. Once the margins on natural gas purchases from marketers fell to +/-5%, the marketers' profit margins fell to unacceptably low levels.

Although natural gas marketers and aggregators were allowed to furnish the customer a consolidated bill, the customer received no credit for this cost from the utility. Moreover, the utility maintained control of the meter and the natural gas ESP had to delay his billing until he received the data from the utility. Utilities refused to provide the data to the customer in computer readable form and the ESP had to re-data enter the information to produce customers' bills. All of these hurdles resulted in additional costs for providing the services with no offsetting credits.

Q9 Does this conclude your testimony?

A9 Yes.

NANCY I. DAY

CAREER SUMMARY

Senior executive with extensive experience managing large line and staff organizations through profound business, regulatory and market changes. Managed regional utility operations and facilities with a focus on improving cost effectiveness and customer service. Led regulatory initiatives during a period of deregulation. Built coalitions and successfully developed consensus solutions to business and regulatory issues. Results-oriented, team-based leader with expertise in the following:

Regulatory Affairs	Governmental Affairs	Administrative Law
Facilities Management	Customer Service	Materials Management
Purchasing	Risk Management	Labor/Management Relations

ACCOMPLISHMENTS

New Energy Ventures, Inc., Pasadena, CA 1995-Present

The nation's first Energy Agent, representing buyers in competitive electricity and natural gas markets.

Vice President -Customer Services (1995-Present)
Develop competitively bid portfolios of electricity and natural gas for NEV clients, direct the provision of an array of customer services including portfolio management, billing, management reports, regulatory analysis and advocacy.

Southern California Gas Company, Los Angeles, CA 1968-1995

The nation's largest natural gas distribution company serving almost 5 million customers. Annual revenues of $3 billion.

Vice President, Regulatory Affairs (1990-1995)
Senior officer responsible for developing and executing regulatory strategies, directing regulatory proceedings and maintaining effective agency contacts and relationships. Managed the staff of 30 professionals responsible for obtaining required regulatory authorizations from the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the Federal Energy Regulatory Commission. Testified before the California Legislature and presented oral arguments before the CPUC and the CEC.

- Led the regulatory initiatives that resulted in the landmark CPUC cost allocation decision to eliminate decades of cross-subsidies between customer classes.
- Directed the company's response to a CPUC-ordered management audit. This comprehensive audit examined every aspect of company operations over a 5-year period and resulted in no adverse findings.
- Implemented aggressive settlement strategies that successfully reduced litigation costs, regulatory delays and obtained the desired business results.
- Reduced the department's operating budget by 35% over 4 years.

Division Manager (1988-1990)
Senior operations manager responsible for the provision of natural gas and related services to 570,000 customers in the South Coastal Division. Managed over 700 employees and $60+ million budget related to the following: installation and maintenance of distribution pipelines and associated metering facilities, meter reading, telephone call center, bill reconciliation, collection, in-home appliance maintenance and repair, and public/government affairs.

- Refocused employee attention away from internal company processes to delivery of customer satisfaction. Customer complaints reduced by 38%.
- Dramatically improved labor/management relations and employee morale. Reduced grievances by 60% and improved employee safety by 22%.
- Instituted the first 12-hour telephone call center operation to improve customer service.
- Merged two divisions into one and consolidated the operation in a new headquarters.
- Revamped market research to obtain better information from our customers regarding customer satisfaction.

Manager of Material Services (1986-1988)
Managed the provision of centralized contracting ($150 million), purchasing ($120 million), warehousing, material distribution and inventory control services. Established functional policy for decentralized purchasing, contracting, and material management. Also managed the specialized fabrication and repair shops and the investment recovery operation.

- Lowered material delivery costs by 12%.
- Transformed a salvage sales operation into a profitable investment recovery operation and recycling program. Generated $1.5 million additional revenue per year.
- Redesigned the material distribution system to eliminate 60 local storerooms.

Manager of Risk Management and Claims (1985-1986)
Managed the placement of insurance, covering all aspects of the company's operations and assets, and the negotiation, settlement and litigation of claims against the company for property damage and personal injury.

- Completed the first comprehensive review of company loss control programs and recommended the strategy for increasing employee and public safety while reducing costs by as much as 30%.
- Instituted an aggressive contact program to achieve timely and low cost resolution of claims against the company.

Manager of Headquarters Services (1983-1985)
Managed the operation and maintenance of over 1 million square feet of office space in 5 different locations. Responsibilities included the following building occupant services: communications, reprographics, janitorial, mail and messenger, automotive maintenance, craft shops, archives, cafeterias, and travel.

- Created an in-house travel agency to earn commissions on all travel services. Offset costs by $100,000.
- Instituted a second shift in the reprographics operations to improve cost efficiency. Productivity increased by 26%.
- Instituted a cost planning and control system.

EDUCATION & PROFESSIONAL ACTIVITIES

Harvard University, Graduate School of Business Administration -
Advanced Management Program
University of Redlands - B.S. Business Administration
University of Southern California - Certificate of Management Effectiveness
Chairperson, Southern California Regional Purchasing Council

ORIGINAL

CERTIFICATE OF SERVICE

I hereby certify that on June 19, 1997, I caused a true and correct copy of New Energy Venture, Inc.'s Direct Testimony and Interrogatory Responses NEV-I-1 to 22 to be served in the manner indicated, upon the following counsel at the addressed noted below:

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Joseph A. Dworetzky

Dated: June 19, 1997

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MEM

BY FEDERAL EXPRESS

June 19, 1997

James J. McNulty, Prothonotary
Pennsylvania Public Utility Commission
Room B-20, North Office Building
P.O. Box 3265
Harrisburg, PA 17107-3265

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

Dear Mr. McNulty:

I enclose for filing with the Commission an original and three copies each of the Testimony of Peter A. Bradford and the Testimony of Richard H. Silkman on behalf of of Senator Vincent J. Fumo, CEPA, Tenant Action Group, Action Alliance of Senior Citizens, ACORN, and John W. Long Jr.

Yours truly,

STEVEN P. HERSHEY

cc Service list

DOCUMENT FOLDER

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER
SECTION 2806 OF THE PUBLIC UTILITY CODE

DOCKET NO. R-00973953

DIRECT TESTIMONY OF PETER A. BRADFORD

FILED ON BEHALF OF

SENATOR VINCENT J. FUMO
CEPA
ACORN
TENANT ACTION GROUP
ACTION ALLIANCE OF SENIOR CITIZENS
JOHN W. LONG JR.

JUNE 20, 1997

Qualifications

Q. Please state your name and business address.

A. Peter A. Bradford, P.O. Box 497, Peru, Vermont.

Q. Please describe your educational background and prior work experience.

A. I have served as chair of the New York State Public Service Commission (1987-1995) and the Maine Public Utilities Commission (1974-75 and 1982-87). I have been a commissioner on the U.S. Nuclear Regulatory Commission (1977-82) and on the Maine PUC (1971-77 and 1982-87). During my terms on the Maine and New York State Commissions I participated in deciding more than 1,000 utility rate cases, of which several dozen involved substantial nuclear issues. I was President of the National Association of Regulatory Utility Commissioners (1986-87) and was at different times a member of its committees on electricity, gas and communications as well as its Executive Committee and its subcommittee on nuclear issues. I was briefly Maine's Public Advocate (1982). After leaving the New York State Public Service Commission, I had a one year fellowship with the Regulatory Assistance Project (RAP), writing and teaching on energy regulation.

I have written a number of articles on utility regulation and energy policy, as well as one book concerning energy policy. I am a graduate of Yale University (1964) and Yale Law School (1968). A complete resume is attached to this testimony as Appendix A.

Q. Please describe the nature of your current consulting activities.

A. I continue to work part-time with RAP, though my testimony in this proceeding is not on RAP's behalf. In addition, I have testified on aspects of strandable cost recovery in Vermont (on behalf of the Department of Public Service) and New Hampshire (on behalf of the Office of Consumer Advocate). I have also advised on this subject in Maryland (on behalf of the Maryland People's Counsel), and I have advised the Vermont Legislature on electricity restructuring. In recent months, I have also advised on aspects of restructuring in Nevada and Ohio and on merger-related matters in Kansas and Washington, D.C. The testimony that I gave in Vermont was subsequently adapted for publication in Public Utilities Quarterly.

I have recently served on a panel advising the European Bank for Reconstruction and Development as to whether the completion of nuclear power plants at Rivne and Khmelnitsky in Ukraine represent the least cost way to replace the remaining Chernobyl units, which are to be closed in 2000. I am also advising the government of Armenia on its newly enacted energy law and on regulatory policy generally. In the past two years, I have taught courses on regulation and restructuring in Russia, Indonesia and India.

Purpose and Scope of Testimony

Q. What is the purpose and scope of your testimony?

A. I have been retained by the Office of State Senator Vincent J. Fumo and CEPA, TAG, Action Alliance of Senior Citizens, ACORN, and John W. Long, Jr. to develop a framework for analyzing the Application of PECO Energy Company ("PECO") for approval of its restructuring plan under Section 2806 of the Public Utility Code. My testimony demonstrates that neither a regulatory compact nor constitutional considerations require Pennsylvania to compel recovery of all strandable investment. Pennsylvania is free to negotiate or adjudicate strandable investment to the full extent allowed by statute to bring about a result that best balances and makes secure the legitimate expectations of all parties and of the public. My testimony in this proceeding expands upon the testimony that I gave in Docket No. R-00973877. The pertinent part of that testimony is attached as Appendix B and should be considered an integral part of this testimony.

Q. Have there been significant developments since your previous testimony that would cause you to change your conclusions?

A. No. To the best of my knowledge, no court has endorsed anything like the constitutional claims advanced by PECO. Nor are Commissions inclining in that direction. A New York Supreme Court decision rejecting arguments similar to those now presented by PECO[1] has since been reaffirmed by the same Judge in dismissing a petition for clarification[2]. His decision is being appealed.

The Texas Public Utilities Commission has recently rejected similar contentions from the Central Power and Light Company[3] as has the New Hampshire Commission rejected them from

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[1]"These arguments (existence of a regulatory compact that would be breached by failure to guarantee full recovery) are contradicted by the public service law and have repeatedly been rejected by the courts (citations omitted)", Energy Association of New York State et. al v. New York PSC 653 NYS 2d 502, 174 PUR 4th 406 (Sup. Ct. 1996).

[2] Supreme Court, Albany County, April 18, 1997. Slip opinion, Index no. 5830-96.

[3]Application of Central Power and Light Company for Authority to Change Rates, Texas PUC, Docket No. 14965, March 31, 1997.

Public Service Company of New Hampshire[4]. The Pennsylvania Commission has reserved the issue for further consideration in this proceeding[5].

Q. Have you reviewed the prefiled testimony of J. Gregory Sidak in this proceeding?

A. I have.

Q. Does his testimony require modification of your conclusions?

A. No. If anything, Mr. Sidak's testimony has enhanced my assurance both that there is no regulatory compact of the type he asserts and that negotiating, conditioning or even denying some substantial recovery of strandable investment would not be confiscatory or in some other way a violation of the Constitution or of the rights of investors in Pennsylvania utilities.

There are several reasons for this conclusion:

First, Mr. Sidak takes a singularly one-sided view of the events and cases that he cites. Utility history is replete with state decisions to permit competition that impaired the value of previously granted franchises[6]. If an ancient regulatory compact actually required compensation

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[4]"Restructuring New Hampshire's Electric Industry: Final Plan", DR 96-150, Legal Analysis, February 28, 1997.

[5]Docket No. R-00973877, May 22, 1997, p.26.

[6]For example, the early electric franchises quickly took the entire lighting business from their predecessor manufactured gas franchisees. Telephone franchises undermined the value of the telegraph. Trains undermined canals and were in turn diminished by trucks. Street railways lost business to taxi franchises. Furthermore, franchises often were not exclusive even within a particular industry. It was not uncommon for city councils to grant overlapping electric franchises. As one history describes this process, "Competition of electric lighting with gas lighting has driven the gas industry into other lines of service.......These forms of competition....when no new business of a different nature can be secured, result finally in receivership and bankruptcy", J.M. Bryant and R.R. Herrmann, Elements of Utility Rate Determination, (New York, McGraw-Hill, 1940), p. 235, quoted in Kenneth Rose, "An Economic and Legal Perspective on Electric Utility Transition Costs" NRRI, Columbus, Ohio, 1996), p. 62-63.

for assets stranded by decisions to permit competition in areas of regulated monopoly franchises, dozens of court cases establishing and construing that compact would have been inevitable long before now. Instead, Mr. Sidak offers only a handful of toll bridge cases dependent on the terms of the specific franchise involved[7].

Furthermore, Mr. Sidak's assertion of a smooth evolution from the contractual aspects of early franchises into state regulation is incorrect. State regulation was not an extension of the contractual aspect of franchise regulation but a repudiation of it. As Charles Phillips, Jr's treatise makes clear,

> "the franchise as actually used proved a defective instrument for detailed regulation....Changes in the prescribed rates or in the service standards were made with great difficulty. This difficulty was due to a Supreme Court decision that held that a franchise had the status of a contract, which a state could not impair (citing Trustees of Dartmouth College v. Woodward, 4 Wheaton 518, 643 [1819]); thus both parties had to approve a change....It was often impossible, consequently, for franchise or charter provisions to be changed 'however ill considered or antiquated with respect to current need for regulation they might be (citation omitted)'...Direct legislative control was inflexible as well as slow. Local franchise control had the same defects. Each of these methods was incapable of adapting to the development of an industrialized and highly

[7]Mr Sidak's testimony omits reference to one toll bridge case that was central to his article, "Deregulatory Takings and Breach of the Regulatory Contract", 71 NYU Law Review 4, 851 (October, 1996). In that case, Charles River Bridge v. Warren Bridge, 36 U.S. 420, 9 L.Ed. 773 (1837), a portion of the majority opinion that he did not mention in the NYU article heartily rejects his concept of implied contracts:

> "And what would be the fruits of this doctrine of implied contracts on the part of the states...if it should now be sanctioned by this court? To what results would it lead us? If it is to be found in the charter to this bridge, the same process of reasoning must discover it in the various acts which have been passed within the last forty years, for turnpike companies...Let it once be understood that such charters carry with them these implied contracts, and give this unknown and undefined property;...and...we shall be... obliged to stand still, until the claims of the old turnpike corporations shall be satisfied; and they shall consent to permit the states to avail themselves of the lights of modern science, and to partake of the benefit of those improvements which are now adding to the wealth and prosperity, and the convenience and comfort, of every other part of the civilized world...This Court are not prepared to sanction principles which must lead to such results.", at 542-43.

complex society - a development requiring expertise, flexible regulation and continuity of policy."[8]

In short, the contract characteristics of municipal franchises were among the main reasons that state regulation supplanted them. It makes little sense then to argue that regulation embodied the very contractual attributes that it was intended to correct.[9]

Third, Mr. Sidak does not explain the inconsistency between Pennsylvania's longstanding policy of disallowing prudent investment not found to be used and useful and his articulation of the regulatory compact. If his view were indeed the law of the land, the Pennsylvania policy would have been overturned years ago, and with it New Hampshire's anti-CWIP statute which forced Public Service Company of New Hampshire into bankruptcy without any finding of imprudence in the late-1980s.

Nor does Mr. Sidak discuss the Market Street Railway[10] line of cases, which hold that a utility need not be reimbursed for losses occasioned by competition even when that competition is itself sanctioned, licensed or otherwise assisted by the state.

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[8]Phillips, The Regulation of Public Utilities, pp. 130-132.

[9]My testimony in docket no. R-00973877 (p. 8) notes also the rule "universally applied...that the grant will be construed in favor of the sovereign and against the grantee" Waukeag Ferry v. Arey, 128 Me. 109, at 115 (1929). This rule appears similar to the "unmistakability doctrine" that is central to the Baumol/Merrill critique (infra, p.)of the Sidak regulatory contract. As they describe it, "This doctrine asserts that promises by the government to forbear from certain types of future regulatory action -- in other words, promises of the sort said to be included in the regulatory contract -- will be enforced by the courts only if they are set forth in 'unmistakable' language", at p. 13. The authors doubt that Mr. Sidak's alleged contract can meet the test of unmistakability.

[10]Market Street Railway Co. v. Railroad Commission of California et al., 324 U.S. 548 (1944) and Public Service Commission of Montana et al. v. Great Northern Utilities Co., 289 U.S. 130 (1932), discussed in my previous testimony, pp. 15-16.

Mr. Sidak's reliance on the 1996 Report of the President's Council of Economic Advisors is also unconvincing. The 1997 Report circumscribes the prorecovery exuberance of the 1996 version. It states "At the same time, however, regulated firms may engage in wasteful investments if (strandable investment) recovery is guaranteed unconditionally. To avoid creating this incentive, a presumption in favor of cost recovery should apply only for costs incurred to comply with specific regulatory mandates or before competition became a significant prospect."[11]. The telecommunications section adds a further qualification, that "such recovery should be limited to investment expenses not already recovered through past earnings"[12]. While these qualifications, like the 1996 Report, misuse utility terminology in ways that show the CEA to be unfamiliar with the fundamentals of the strandable cost issue, the movement away from the unqualified endorsement of recovery set forth in the 1996 Report is unmistakable.

Finally, Mr. Sidak's testimony, like the NYU article, is advocacy, not scholarship. He has marshaled all evidence that can be bent to his conclusion and has chosen not to address much evidence and argument to the contrary. Consequently, as ardent a compact proponent as Alfred Kahn asserts that Messrs. Sidak (and William Baumol and I, for that matter) "overstate their cases...which creates a wonderful opportunity for a reasonable person like me to take a firm stand in the middle"[13]. Dr. Kahn, who has consistently refused to support an absolute right to full recovery, goes on to note that Mr. Sidak's "seeming to insist on the necessity of total recovery of

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[11] 1997 Economic Report of the President 207.

[12] Ibid, at 204-205.

[13] Alfred Kahn, "Competition and Stranded Costs Revisited", University of New Mexico School of Law Symposium, August 2, 1996, p. 10

costs in the absence of explicit findings of imprudence, clearly impl(ies) that the consuming public will lose more in higher costs of capital henceforward than they gain from illegitimate disallowances. Not only can no one make such a statement with confidence in my opinion; it is surely subject to substantial discount, in recognition of investors' notoriously short memories".[14]

Irwin Stelzer, Mr. Sidak's colleague at the American Enterprise Institute and Director of AEI's Regulatory Policy Studies, has questioned assertions of a regulatory compact and suggested that electric utility investors have been warned of and compensated for the risk of changes in government policy[15].

The view that Mr. Sidak goes too far is also set forth in two responses to the NYU Law Review article. Both authors strongly doubt that full recovery of strandable investment can be justified by the Sidak reasoning[16].

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[14]Ibid. As to my assertion that the regulatory compact does not date back more than 15 years, Dr. Kahn writes, "While I leave a definitive assessment of this claim to the legal archeologists, I have the impression it is essentially right (footnote omitted)", at pp.6-7.

[15]See Stelzer, "Stranded Investment: Who Pays the Bill", remarks to the Southeastern Electric Exchange, March 30, 1994, p. 6ff, and "Restructuring the Electric Industry: The Next Step", remarks at the JFK School of Government, May 24, 1995. Messrs. Stelzer and Sidak do not claim to speak for AEI.

[16]Stephen Williams, "Deregulatory Takings and Breach of the Regulatory Contract: A Comment" 71 NYU Law Review 1000, asserting as to the argument that all costs not specifically disallowed are prudent and should be recovered, "First, this may be empirically wrong in many cases--that is to say costs are commonly not evaluated by the regulatory agency at all unless challenged in a rate case. But more generally, if one of the defects of regulation is that we doubt the ability of regulators to identify inefficiency, the fact of their failure to do so proves little... Can one clearly say that there is a compelling principle of political economy requiring compensation for one hundred percent of the losses attributable to inefficiency?", at pp 1001, 1002. And "The article's sketch of takings law strikes me as somewhat more protective than the present reality", at p.1005.
Oliver Williamson, "Deregulatory Takings and Breach of the Regulatory Contract: Some Precautions", 71 NYU Law Review 1007, stating "...To describe all behavior antiseptically 'as if'

Even Dr. Baumol, an occasional coauthor with Mr. Sidak, seems to be having second thoughts. He has recently coauthored (with Thomas W. Merrill) an article that questions both the regulatory compact as described by Mr. Sidak and its approach to valuation of the asserted utility entitlement[17].

Q. *Does Mr. Sidak's discussion of the <u>Loretto</u>[18] and <u>U.S. Trust</u>[19] cases establish a* likelihood of confiscation if Pennsylvania grants less than full recovery or conditions full recovery on specific conduct by PECO?

A. No. Both of these cases (and the recent <u>Winstar</u>[20] decision on which Mr. Sidak has relied elsewhere) were argued to the New York court as well as to the New Hampshire PUC and the Vermont Public Service Board in the same manner that Mr. Sidak and PECO argue them in

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there were full and candid disclosure and 'as if' all investments were prudent is unwarranted. Contrary to Sidak and Spulber, I am not persuaded that the 'formality of the regulatory process...' should be described as a reliable mechanism for verifying the mutuality of voluntary exchange and a meeting of the minds. Neither am I persuaded that investments made by a natural monopolist are assuredly "prudently incurred' because '...regulators and intervenors carefully scrutinized the utility's investments before they were made'. Finally...Sidak and Spulber appear to assume that regulated firms are operated in least cost ways. That is unduly sanguine", at p. 1007.

[17]Baumol and Merrill, "Deregulatory Takings, Breach of the Regulatory Contract and the Telecommunications Act of 1996", paper presented at The Fifteenth National Regulatory Conference, Williamsburg, Va., May 5-6, 1997.

[18]<u>Loretto v. Teleprompter Manhattan CTV Corp.</u>, 458 U.S. 419 (1982), discussed in Mr. Sidak's prefiled testimony, pp 35-42.

[19]<u>United States Trust Company v. New Jersey</u>, 431 U.S. 1 (1977), Sidak prefiled testimony, p. 18.

[20]<u>United States v. Winstar Corp.</u>, 116 Sup. Ct. 2432 (1996)

Pennsylvania. The arguments were found to be unconvincing[21] . In addition, Mr. Sidak himself made the same arguments before the Texas Public Utilities Commission, which has rejected his view[22]. The New York Supreme Court found Loretto to be beside the point because of

> "the vital distinction between a permanent physical occupation by a private enterprise and a regulation that merely restricts the use of a property. Retail wheeling is not affected by this holding inasmuch as the carrying of a competitor's electricity is not a permanent physical occupation.....In Rochester Gas and Electric v. PSC, 71 NY 2d 313 (1988 the New York Court of Appeals rejected the argument that to require a utility to carry a competitor's natural gas resulted in a physical invasion of RG&E's distribution system.....citing Pennsylvania Gas v. PSC, 225 NY 397 [1919], aff'd 252 U.S. 23 [1920]; Pipeline Cases 134 US 548 [1913]; Kansas City Power and Light Corp. v. State Corp. Commission 238 Kan 842 [1986], appeal dismissed, 479 U.S. 801 [1986]."

Q. Have you reviewed the testimony of Joseph Brennan in this proceeding?

A. Yes.

Q. Does Mr. Brennan's testimony require modification of your testimony?

A. No. As with Mr. Sidak, Mr. Brennan's testimony strengthens mine. In his case, this occurs because, even after his recommended adjustments are made, the returns earned by utility investors are in the same range as those earned by investors in unregulated companies during the 1972-1992 period[23]. While it is true that PECO did less well than the industry as a whole, much of that

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[21] Energy Association of the State of New York, supra, note 1 ;"The Power to Choose", Vermont Public Service Board, Docket No. 5854, December 31, 1996, pp 56-66; "Restructuring New Hampshire's Electric Industry", Legal Analysis, supra, note 4 .

[22] Application of Central Power and Light Company, supra, note 3, pp. 66-67, 81-84.

[23] Mr. Brennan also adjusts the data from the Foley-Thompson study to eliminate the averaging of holding periods. By so doing he makes the result valid only for investors who bought and held a utility stock for the entire twenty-one year period, rather than the much larger and more representative group reflected in the Foley-Thompson method, which shows Philadelphia Electric investors to have achieved an overall average return of 13.89%, 55th of the 89 companies studied.

shortfall can be attributed to problems of the company's own making, especially the problems stemming from the Company's inadequate response to the sleeping control room operators at Peach Bottom, which earned PECO one of the lowest appraisals ever given by the Institute for Nuclear Power Operations and led to the replacement of senior management.

In addition, Mr. Brennan continues to maintain that investors had no warning of potential losses from competition. As indicated in the earlier proceeding, this is neither correct nor entirely relevant[24]. Investment community awareness of potential competition has been growing for many years. Competition was widely discussed in the utility business, by Mr. Brennan[25] among others[26], from the early 1980s onward. In Pennsylvania, the Philadelphia Inquirer ran an extensive feature entitled "Have the Utilities Outgrown Monopoly?" in its June 20, 1982 Business Section. . This article mentioned a task force chaired by Lieutenant Governor Scranton to study reforms,

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In addition, the use of a single period is subject to distortion based on the beginning or end dates chosen.

[24]Appendix B, pp. 13-18.

[25]Appendix B, p.17, note 21. Indeed, the debate is as old as the industry itself. The NRRI work cited in footnote 5, contains this 1941 quotation "While many have been resigned to the notion of "natural monopoly", the sanctity of the concept has not gone unchallenged. In fact, during the past thirty years there have been at least 120 reported cases in which the desirability of competition in gas and electricity has been in issue before a state commission", Henry Kohn, Jr., A Re-examination of Competition in Gas and Electric Utilities," The Yale Law Journal, 50 (1941): 875-91.

[26]"Let's End the Monopoly", speech by William Berry, President, Virginia Electric Power Company, Edison Electric Institute Fall Financial Conference, October 6, 1981, stated, "Let's open electricity generation to competition - with free entry, no franchises and no obligation to serve.". Berry expanded this theme in "The Case for Competition in the Electric Power Industry", Public Utilities Fortnightly, September 16, 1982, p. 13. The Fortnightly asserted in the descriptive lead-in that "the current debate over electric power deregulation is moved beyond its initial exchange of generalities".

including deregulation. It mentioned also that the Edison Electric Institute had just completed "a detailed study of various deregulation schemes designed to foster more competition and efficiency in the industry".

Furthermore, the possibility of substantial losses and the nonexistence (or, as many in the industry allege, the "dishonoring" or "failure") of the regulatory compact, were part of the conventional wisdom of the electric utility industry as long as 15 years ago[27]. Mr. Brennan's vision of utility investors putting their money into PECO in reliance on the regulatory compact to provide complete security just cannot be reconciled with reality. Indeed, the President of the Pennsylvania Electric Association in 1985 warned prospective investors in Pennsylvania utilities:

> Show me the investor who will put his money into electric utility securities under existing conditions and I'll show you the embodiment of the principle that a fool and his money are soon parted.[28]

Pennsylvania investors took the risk levels that were apparent at the time that they invested their money. Of course, no one would assert that this provides a basis for expropriation of their capital, but nor can they claim ironclad protection against risk of substantial loss.

Q. After reading the testimony of Mr. Sidak and Mr. Brennan, what is your advice to the Pennsylvania Commission?

A. I would reiterate the central points from my testimony in the securitization proceeding, i.e.

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[27]Vincent Butler, president of the Pennsylvania Electric Association warned in a December, 1985 article in the Public Utilities Fortnightly, that the compact had been "bent out of shape in the past decade, but it now appears to be disintegrating". He added that regulators "impose on utility investors a new dimension of risk (nonrecovery of prudent investment if it is excess capacity) not previously experienced", "A Social Compact to Be Restored", Public Utilities Fortnightly, *December 26, 1985, pp. 19, 20.*

[28]Ibid, p. 20.

that there has never been a societal compact that compels a regulatory commission to assure the full recovery of every dollar of investment not found to have been spent imprudently. Instead, one finds only general arrangements that varied from state to state and from time to time, arrangements that might give rise to investor hopes but not to the rights now claimed by utilities.

Strandable investment is the public's best road to an effectively competitive and an environmentally acceptable future. Regulators, legislators and others in the public sector must not give it away until that future is well secured. The opportunity for recovery of a substantial amount of stranded costs should be expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead.

Q. Does this complete your testimony?

A. Yes.

APPENDIX A

PETER A. BRADFORD
P.O. BOX 497
PERU, VERMONT 05152
(802) 824-4296

PROFESSIONAL EXPERIENCE:

March 1996- date

Energy Advisor*; Also, Affiliated with Regulatory Assistance Project. Member of International expert panel advising European Bank for Reconstruction & Development on least cost alternatives to continued operation of Chernobyl; Advised on utility restructuring in Indonesia, India, Armenia, District of Columbia, Maryland, Ohio, Texas and Vermont; Testified on restructuring in Vermont, New Hampshire and Pennsylvania.*

February 1995 - March 1996

***Fellow*, Regulatory Assistance Project**
Project funded by the U.S. Dept. of Energy, the Environmental Protection Agency and foundations to provide assistance to state and federal regulatory commissions on energy and environmental matters. Advised on utility regulation and restructuring in India, Russia and Armenia.

June 1987- January 1995

***Chairman*, New York State Public Service Commission**
Albany, New York
CEO of state agency charged with overseeing $29 billion annual revenues of New York utilities. Responsible for developing and implementing consumer and environmental protection policies, transitions from monopoly to competition in energy and telecommunications industries. 700 employees, $65 million budget.

July 1982- June 1987

***Chairman*, Maine Public Utilities Commission**
Augusta, Maine
CEO of state agency charged with overseeing $2 billion annual revenues of Maine utilities. Responsible for developing and implementing consumer and protection policies, including competitive independent power production and energy services as well as adjusting to the break-up of employees, $4 million budget.

environmental
bidding for
conservation
AT&T. 60

March 1982-June 1982	***State of Maine Public Advocate*** *First full-time Maine public advocate; intervened on consumers' behalf in telephone and electric cases; oversaw staff of 6; prepared briefs; cross-examined witnesses.*
Aug. 1977-March 1982	***Commissioner*, United States Nuclear Regulatory Commission, Washington, D.C.** *One of five commissioners in the federal agency whose responsibilities included safety of nuclear power plants and other nuclear facilities; preparing licensing criteria for a nuclear waste repository; licensing exports of nuclear fuel and reactors pursuant to Nuclear Nonproliferation Act; assisted in major upgradings of regulatory and enforcement processes in wake of Three Mile Island accident. 3000 employees, $250 million budget.*
Dec. 1971-Aug. 1977	***Commissioner*, Maine Public Utilities Commission** ***Chairman*** (Aug. 1974- July 1975),**Augusta, Maine.**
Sept.1968- Dec. 1971	***Federal-State Coordinator*, State of Maine** *Responsible for many oil, power, environmental and housing matters. Assisted in preparation of landmark Maine laws relating to oil pollution and industrial site selection. Staff Director, Governor's Task Force on Energy, Heavy Industry and the Coast of Maine.*
May 1968-Sept. 1968	***Research Assistant to Ralph Nader*, Washington, D.C.** *Assisted in study of Federal Trade Commission's failure to enforce federal consumer protection laws.*
Aug. 1964-June 1965	**Athens College, Greece** ***Teaching Fellowship***

PUBLICATIONS:

1975	Fragile Structures: A Story of Oil Refineries, National Security and the Coast of Maine, Harper's Magazine Press.
1971- Present	Numerous articles on utility regulation and nuclear power have been published in The New York Times, The Washington Post, The Los Angeles Times , The Boston Globe, Newsday, and The Electricity Journal.

PROFESSIONAL AFFILIATIONS:

Nov. 1986-Nov. 1987	***President*, National Association of Regulatory Utility Commissioners**
1977-1995	**NARUC**, Member, Executive Committee **NARUC**, Member, Electricity Committee **NARUC**, Member, Gas Committee **National Regulatory Research Institute**, Board of Directors
Present	**Nuclear Control Institute**, Board of Directors

EDUCATION:

1964	*B.A*. History, **Yale University**, New Haven, CT
1968	***L.L.B.*, *Yale* University School of Law**, New Haven, CT

AWARDS:

Teaching Fellowship, 1964-1965 (see above)
Honorary Degree, Unity College, 1981.
Environmental Award, Natural Resources Council of Maine, 1979.

PERSONAL:

Married (Susan Symmers Bradford)
Three Children (Arthur, Laura, Emily)

PUBLICATIONS of Peter A. Bradford

Books

Fragile Structures: A Story of Oil Refineries, National Security and the Coast of Maine, 1975, Harpers Magazine Press.

Law Review

"Maine's Oil Spill Legislation", Texas International Law Journal, Vol.7, No.1, Summer 1971, pp.29-43.

Articles

Book Review: *"The British Electricity Experiment - Privatization: the Record, the Issues, the Lessons"*, Amicus Journal, forthcoming.

"Gorillas in the Mist: Electric Utility Mergers in Light of State Restructuring Goals", The National Regulatory Research Institute Quarterly Bulletin, Spring, 1997.

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"Market-Based Speech", The Electricity Journal, September, 1994, p.85.

"In Search of an Energy Strategy", Public Utilities Fortnightly, 1/15/92.

continued: Publications of Peter A. Bradford

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Foreword to: Regulatory Incentives for Demand Side Management, Nickel, Reid, David Woolcott, American Council for Energy-Efficient Economy, 1992, pp.ix-xi.

"Boats Against the Current", The Electricity Journal, October, 1991, p.64.

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'Parallel to the Nuclear Age', Yale University 25th Reunion book, 1989.

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APPENDIX B

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKET NO. R-00973877

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY
CODE

DIRECT TESTIMONY OF

PETER BRADFORD
RICHARD H. SILKMAN

FILED ON BEHALF OF

*** THE OFFICE OF STATE SENATOR VINCENT J. FUMO ***
*** CEPA ***
*** TENANT ACTION GROUP ***
*** ACTION ALLIANCE OF SENIOR CITIZENS ***
*** JOHN W. LONG, JR. ***

FEBRUARY 28, 1997

DIRECT TESTIMONY OF
PETER BRADFORD AND RICHARD H. SILKMAN

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DIRECT TESTIMONY OF PETER BRADFORD AND RICHARD H. SILKMAN

Qualifications

Q. Please state your names and business addresses.

A. Peter Bradford, P.O. Box 497, Peru, Vermont.

Richard H. Silkman, 163 Main Street, Yarmouth, Maine.

Q. Mr. Bradford, please describe your educational background and prior work experience.

A. I have served as chair of the New York State Public Service Commission (1987-1995) and the Maine Public Utilities Commission (1974-75 and 1982-87). I have been a commissioner on the U.S. Nuclear Regulatory Commission (1977-82) and on the Maine PUC (1971-77 and 1982-87). During my terms on the Maine and New York State Commissions I participated in deciding more than 1,000 utility rate cases, of which several dozen involved substantial nuclear issues. I was President of the National Association of Regulatory Utility Commissioners (1986-87) and was at different times a member of its committees on electricity, gas and communications as well as its Executive Committee. I was briefly Maine's Public Advocate (1982). After leaving the New York State Public Service Commission, I had a one year fellowship with the Regulatory Assistance Project (RAP), writing and teaching on energy regulation.

I have written a number of articles on utility regulation and energy policy, as well as one book concerning energy policy. I am a graduate of Yale University (1964) and Yale Law School (1968).

Q. Mr. Bradford, please describe the nature of your current consulting activities.

A. I continue to work parttime with RAP. In addition, I have testified on aspects of strandable cost recovery in Vermont (on behalf of the Department of Public Service) and New Hampshire (on behalf of the Office of Consumer Advocate). I am also testifying on this subject in Maryland (on behalf of the Maryland People's Counsel), and I am advising the Vermont Legislature on electricity restructuring. The testimony that I gave in Vermont was subsequently adapted for publication in Public Utilities Quarterly.

I am serving on a panel advising the European Bank for Reconstruction and Development as to whether the completion of nuclear power plants at Rivne and Khmelnitsky in Ukraine represent the least cost way to replace the remaining Chernobyl units, which are to be closed in 2000. I am also advising the government of Armenia on its proposed energy law and on regulatory policy more generally. In the past 18 months, I have taught courses on regulation and restructuring in Russia, Indonesia and India.

Q. Dr. Silkman, please describe your educational experience and prior work background.

A. I have served on the faculties of the State University of New York at Stony Brook (1978-1983) and the University of Southern Maine (1983-1986), where I also served as the Acting Director of the Public Policy and Management Program (1986). I was appointed by Governor John McKernan to become the Director of the Maine State Planning Office (1987-1992), a cabinet level agency with broad policy and planning responsibilities, including economic development, energy, taxation, budgetary, land-use management and health care. In this capacity, I chaired a number of state level committees and multi-agency task forces and was on the Board of Directors of a variety of quasi-governmental agencies including the Maine Development Foundation, the Maine Science and Technology Commission and the Maine World Trade Association. I also chaired a number of Staff Advisory Committees of the National Governors' Association, including its Task Force on Health Care (1989-90), Telecommunications Committee (1987-88) and Human Resources Committee (1990-91).

I have been a member of the Board of Directors of the Council of Governors' Policy Advisors (CGPA), an affiliate of the National Governors' Association (1988-92), and its President (1990-1991). I have an undergraduate degree in economics (with honors) from Purdue University (1972) and a Ph.D. in economics from Yale University (1980).

Q. Dr. Silkman, please describe the nature of your current consulting activities.

A. I serve as a consultant on energy matters for a variety of clients in Maine and the northeast. These clients include a trade association of Maine's largest industrial consumers of electricity, a Fortune 500 multi-state retail grocery company, and a municipal water district. In representing these clients and others, I have negotiated over a dozen special electric rate contracts with investor owned public utilities and have testified before the Maine Public Utilities Commission on matters of rate design, the justness and reasonableness of rates and electric utility industry restructuring.

Q. Is this testimony being sponsored jointly?

A. Yes. We are jointly offering this testimony. Mr. Bradford, however, is the lead author of Section I, as this section focuses primarily on the legal basis for stranded cost recovery. Dr. Silkman is the lead author of Sections II and III, which address economic issues and consequences of securitization and the timeliness of the PECO Energy Company's application.

Purpose and Scope of Testimony

Q. What is the purpose and scope of your testimony?

A. We have been retained by Community Legal Services, Inc. of Philadelphia on behalf of several community organizations and the Office of State Senator Vincent J. Fumo to develop a framework for analyzing the Application of PECO Energy Company ("PECO") regarding the issuance of a Qualified Rate Order ("QRO") under Sections 2808 and 2812 of the Public Utility Code. Our testimony is divided into three (3) sections. In the first section, we will demonstrate that there has never been a societal compact that compels a regulatory commission to assure the full recovery of every dollar of investment not found to have been spent imprudently. Rather, the opportunity for recovery should be expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead.

The second section of our testimony will demonstrate that securitization, as proposed by PECO in its application for a QRO, represents a fundamental shift of investment risk from shareholders to ratepayers, without adequate compensation to ratepayers for taking on this additional risk.

Finally, in the third section of our testimony, we will show that PECO's attempt to accelerate the securitization process runs counter to sound public policy and appears to violate the intent, if not the letter, of the recently enacted Electricity Generation Customer Choice and Competition Act. PECO's effort to place the cart before the horse by securing its recovery of stranded costs prior to an adjudicatory proceeding in which the Pennsylvania Public Utilities Commission ("PUC") approves that utility's restructuring plan, quantifies the recoverable amount of stranded costs and evaluates that utility's mitigation efforts imposes unnecessary risks on ratepayers while providing potentially substantial benefits to shareholders. PECO's Application should therefore be rejected pending a comprehensive review of its Restructuring Plan based on the "interdependent standards" set forth in Section 2804 of the Electric Generation Customer Choice and Competition Act.

Section I There has never been a societal compact that compels a regulatory commission to assure the full recovery of every dollar of investment not found to have been spent imprudently. The opportunity for recovery of a substantial amount of stranded costs should be expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead.

Q. Please explain why you believe that there has never been a societal compact that compels the PUC to assure full recovery of stranded investment.

A. Many utilities across the country have been alleging that commissioners are bound by an ancient and clear compact, understood by regulators, investors, customers and utilities since the beginnings of utility regulation. As we will discuss in more detail below, we have found no discussion of such a compact before the early 1980s. Even then, one finds not affirmation of an ongoing agreement but warnings and laments that the compact is broken, scarcely a sound basis for naive investor reliance. Before then, one finds only general arrangements that varied from state to state and from time to time, arrangements that might give rise to investor hopes but not to the rights now claimed by utilities.

Q. Does the absence of a societal compact then compel the PUC to disallow recovery of any stranded costs?

A. No. The absence of such a compact does not compel such a result. Many states have made bargains whose explicitness rebukes those who claim specific entitlements based on gauzy and implicit historic arrangements. New York's Shoreham settlement, the allowances pursuant to which Central Maine Power Company sold its interest in Seabrook, and state-ordered power purchase contracts or DSM programs might be such arrangements. Actual prudence findings count heavily in states that have always allowed full recovery of prudent investments.[1]

Furthermore, a substantial amount of strandable investment has already been recovered, whether the 1994 California announcement or the federal Energy Policy Act of 1992 or the competitive developments throughout the utility industry after the late 1970s are used as starting points for the dissolution of expectations based on pure monopoly. Because neither these sums nor the amounts being collected daily under present rates will be refunded, a complete disallowance seems out of the question.

Q. How, then, do you propose that the PUC should evaluate utility claims for recovery of stranded costs?

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[1] Note, however, that such a bargain cannot be inferred from exhortatory statements or letters from public officials. Utilities that have for years frustrated firm regulatory, legislative and/or gubernatorial exhortations with which they disagreed (concerning, for example, DSM programs or marginal cost pricing) can hardly claim that they rushed headlong into dubious power plants or purchases just because they were told that public officials so desired. Even parallel conduct by a state agency does not excuse a failure by a utility to bring to bear its greater analytical resources and the best judgement of its senior officials. Finally, a regulatory order approves a project as of the date of its issuance. Subsequent cost overruns, contract management questions, or lock-in decisions must be evaluated in terms of the knowledge available when they took place.

A. Since the most sensible compact proponents do not insist on full recovery of all strandable investment,[2] this issue seems amenable to a resolution in which the opportunity for substantial recovery is expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead.

Q. Please explain the basis for this conclusion.

A. Our conclusion is based on several propositions:

- There never was such a regulatory compact.
- Electric utility investors have long been well aware that serious losses, even bankruptcy, were possible in the electric utility industry and that no compact protected them from technological or regulatory change.
- Electric utility investors have for many years been compensated at levels sufficient to cover the risk of some loss of their strandable investment.
- Not all strandable commitments were prudently incurred.

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[2] See for example, the December, 1994 paper by William J. Baumol, Paul L. Joskow, and Alfred E. Kahn, entitled "The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power," which the Edison Electric Institute submitted to FERC in the rulemaking proceeding that led to Order 888, stating at p.24, "A failure now of policy makers to ensure the companies <u>at least some reasonable level of recovery</u> of their regulatorily approved costs in any transition to competition would leave investors, in effect, with part - a very large part - of the value of their property expropriated by the change in the rules of the game." (emphasis added) Dr. Kahn restated this point in the December, 1994, <u>Electricity Journal</u>, "I have systematically refrained from making recommendations about the extent of the entitlement of utility companies to recover their sunk costs... It has been my consistent explicit policy to leave such determinations to regulators on the basis of considerations of equity, the likely effect of disallowances on the future cost of capital and assessments in the particular circumstances of the extent to which investors might properly be held to have had foreknowledge of the possibility of the change in the rules to their disadvantage or to have been compensated for such risks." at p.80.

A. There never was such a regulatory compact.[3]

Q. Please elaborate further and in more detail on why you do not believe there ever has been a regulatory compact.

A. *Some compact proponents trace the concept back into the last century, before regulation and into* municipal contracting.[4] However, the cases that they cite show only that a franchise is often a contract, not that the franchisee is entitled to any particular rate treatment not spelled out in the franchise. Ignored in their analysis is the rule "universally applied .... that the grant will be strictly construed in favor of the sovereign and against the grantee". [5]

This rule was emphatically applied by the U.S. Supreme Court in Charles River Bridge v. Warren Bridge.[6] In that case, the proprietors of the Charles River Bridge sued because Massachusetts permitted construction of the Warren Bridge, which permitted free passage close to their toll bridge.

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[3] "Actually, there never was a compact - only a wishful delusion by utilities", Charles M. Studness, "The Regulatory Compact that Never Was", Public Utilities Fortnightly, 1 September 1991, p.34. The Vermont Public Service Board has rejected any constitutional or compact-based claim to recovery of stranded investment. "We can find no basis in the cases cited by CVPS [U.S.Trust Co. v. New Jersey, 431 U.S. 1 (1977) and United States v. Winstar Corporation 116 S. Ct. 2432 (1996)] for the proposition that there is a binding regulatory compact between the State and its electric utilities", [Report and Order,] Docket No. 5854, Investigation into the Restructuring of the Electric Utility Industry in Vermont, (December, 1996), p.58.

The New York Supreme Court recently rejected the same claims, noting "These arguments are contradicted by the Public Service Law and have repeatedly been rejected by the Courts." The Energy Association of New York State v. Public Service Commission, State of New York Supreme Court, Albany County, Index No. *5830-96, November, 1996, p.22.*

[4] Rebuttal testimony of J. Gregory Sidak, Application of Central Power and Light for Authority to Change Rates, Texas PUC Docket 14965, pp 13-17, which was expanded in Sidak and Spulber, Deregulatory Takings and Breach of the Regulatory Contract, 71 N.Y.U. L. Rev. No. 4, October, 1996, pp. 851-999.

[5] Waukeag Ferry v. Arey, 128 Me. 109, at 115 (1929)

[6] 36 U.S. 420, 9 L. Ed. 773 (1837)

Despite the contention that the new bridge rendered their franchise of no value , the Charles River Bridge owners' claim was rejected, as was the notion of implying bargains broader than the specific terms of the franchise:

> "And what would be the fruits of this doctrine of implied contracts on the part of the states...if it should now be sanctioned by this court? To what results would it lead us? If it is to be found in the charter to this bridge, the same process of reasoning must discover it in the various acts which have been passed within the last forty years, for turnpike companies...Let it once be understood that such charters carry with them these implied contracts, and give this unknown and undefined property;...and...we shall be... obliged to stand still, until the claims of the old turnpike corporations shall be satisfied; and they shall consent to permit the states to avail themselves of the lights of modern science, and to partake of the benefit of those improvements which are now adding to the wealth and prosperity, and the convenience and comfort, of every other part of the civilized world...This Court are not prepared to sanction principles which must lead to such results."[7]

Bear in mind in this context that the granting of franchises for municipal electric operations (or the decisions of municipalities themselves to undertake such operations) as well as federal efforts to promote the development of the interstate pipeline system must have "stranded" considerable investment in manufactured gas systems of that time. Proponents of a sweeping historical compact protecting such franchises ought to be able to lead us to many cases in which the franchisees were held to be entitled to full compensation for so unforeseeable an introduction of competition.

Q. Mr. Bradford, are the terms regulatory compact or regulatory bargain found in the literature that discusses economic regulation?

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[7] Ibid, at 542-543. For example, the New Hampshire Supreme Court and the Public Utilities Commission have made clear that the franchise in New Hampshire has never precluded retail competition, <u>Appeal of Public Service Company of New Hampshire</u>, (Citation) (1996). A sensible argument for implying a strandable investment guarantee from nonexclusive franchises is hard to imagine.

A. I have not been able to find any references to the phrases regulatory compact and regulatory bargain in any book or article written before 1985.[8] Further, while I cannot claim to recall all of the testimony and argument presented in rate cases during my first term (1971-77) on the Maine Public Utilities Commission, I am reasonably confident that neither phrase was used to support rate increases in those years, when utilities were using every argument that came to mind. Certainly the compact was not central to the arguments.

Neither Bonbright nor Phillips nor Kahn discuss such a compact or bargain in the editions of their leading treatises on utility regulation published in the 1970s. Nor does the concept appear in earlier writings of which I am aware.[9] Dr. Kahn's first use of the phrase apparently came in an August, 1985 op-ed piece in the Wall Street Journal. Because this is an early, clear and typical articulation of the bargain, it is worth examining closely:

> Dr. Kahn warns that commissions that "define prudency on the basis of hindsight, and only for failures... play a regulatory game of heads-the-consumer-wins, tails-the-investor-loses thereby violating the essential basis of public utility regulation...an implicit bargain between consumers and investors that, in exchange for a monopoly franchise, the company accepts the strict legal obligation to serve all customers on reasonable terms. This means that shareholders accept a return on investment equivalent only to something like the market cost of capital...along with

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[8] The earliest reference to such a compact of which I am aware comes from the memories of two individuals who recall that Eugene Meyer, then a cost of capital witness with Kidder, Peabody, asserted such a compact in the early 1980s. According to these recollections, Mr. Meyer was emphatic in stating that the compact had already been broken. His testimony in a 1984 Puget Power and Light case may have contributed to the strong endorsement of the compact's existence that appears in Washington Utilities and Transportation Commission v. Puget Sound Power and Light Co. 62 PUR 4th 557, 581-583 (1984).

[9] A June 17, 1996 letter to the Wall Street Journal by William Baumol and J. Gregory Sidak contends that Professor Gregory Priest has produced ample evidence in published work that such a contract can be traced to the earliest days of public utility regulation. However, the Priest article says nothing of the sort and has nothing to do with the debate over a regulatory compact. Its intent is to establish that the emergence of regulatory commissions ninety years ago was evolutionary from municipal franchise contracting, not a sharp departure. It does say that early regulation is difficult to distinguish from long term contracting dominated by predictable problems of unilateral or mutual adjustment over time in response to changing conditions and that franchise contracts were seldom exclusive...city governments often threatened competition... Priest, "The Origins of Utility Regulation and the 'Theories of Regulation' Debate", XXXVI, Journal of Law and Economics 289 (1993), at 294 and 312.

> the duty conscientiously to anticipate the future needs of the public and to make whatever investments may be necessary in order to meet them efficiently.
>
> This means that if the company makes a particularly successful investment ..., the lion's share of the benefit goes to the consumer....The other side of the bargain is, and has to be, that investors are permitted to earn that same minimum return on the dollars that they put into investments that turn out sour."[10]

Q. Does this quote from Dr. Kahn support a regulatory compact?

A. No. Dr. Kahn is not, in fact, articulating a contract. He is simply articulating a way that regulation ought to work. The relevant question of a utility's right to recover stranded costs turns on whether utility investors had so absolute an assurance that regulation would work in Dr. Kahn's recommended fashion that any risk to the contrary cannot be assigned to them. Alternatively, have they been compensated for bearing such a risk?

B. Investors had good reason to be aware that regulation would not work in the manner described by Dr. Kahn.

Q. Please explain why you believe investors should have understood that the bargain described by Dr. Kahn never characterized regulatory practices?

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[10] Similar formulations appear constantly after 1985, invariably in the context of assertions that the bargain has been broken. See, for example, Charles Phillips, The Regulation of Public Utilities (Arlington, Va.: Public Utilities Reports, 1993, 3rd ed.), p. 21, quoting Irwin M. Stelzer "The Utilities of the 1990s", *The Wall Street Journal*, 7 January, 1987, p.20. The lament for the lost bargain was often accompanied by prophecies of blackouts and brownouts in the early 1990s if the bargain was not restored. See, for example, Vincent Butler, "A Social Compact to be Restored", *Public Utilities Fortnightly*, 26 December, 1985, p 17-21; Peter Navarro, The Dimming of America, (Cambridge, Ma.: Ballinger, 1985) 5-7; Richard J. Pierce, Jr., "Using the Gas Industry as a Guide to Reconstituting the Electric Industry", *Research in Law and Economics* 13, (1991) 14-15.

A. Regulatory practices have varied widely among the 50 states. No one arrangement ever fit them all. Several deviations from Dr. Kahn's statement of the bargain were so pervasive that investors must have been aware of them. The first was the doctrine in many states that customers are not required to pay for property that is not used and useful . The second is the proposition that regulators cannot be expected to compensate investors for values undermined by competition. In addition, investors from the late 1970s forward were subject to a blizzard of articles, speeches and other warnings from the financial community and from utility executives (including PECO's) that regulators were not allowing rate increases adequate to support traditional returns, and that bankruptcy for some utilities (especially utilities like PECO with extensive nuclear facilities) was a real possibility, especially in light of the fact that the recently discovered compact was badly broken.

Q. Please discuss how regulatory authorities and the courts have interpreted the used and useful standard.

A. In many states and at FERC, the used and useful doctrine has provided for the disallowance from rates of prudent investment. In 1981 the D.C. Circuit Court of Appeals restated its affirmation of this result as follows:

> "NEP says that capital prudently invested in a generating facility is taken for public use and therefore must be included in the rate base....The general rule recognized by this court is that expenditure for an item may be included in a public utility's rate base only when the item is 'used and useful' in providing service: that is, current rate payers should bear only legitimate costs of providing service to them."[11]

The D.C. Circuit reaffirmed this view in an en banc opinion by Justice Bork:

[11] NEPCO Municipal Rate Commission v. FERC 668 F.2d 1327, 1333 (1981).

> Absent that sort of deep financial hardship described in Hope, there is no taking and hence no obligation to compensate, just because a prudent investment has failed and produced no return.[12]

The U.S. Supreme Court reached the same result in Duquesne Light and Power v. Barasch.[13] It is clear also that investors could not have believed that the used and useful rule is restricted to a one-time application at the time the plant is ready for service. As a Pennsylvania court held in upholding an excess capacity adjustment in which the Commission denied Philadelphia Electric Company a return on several existing power plants that had previously been included in rate base, "To the degree there is excess capacity there are generating properties that are not used and useful in rendering service to ratepayers."[14] Any other result risks violating elementary statutory construction principles by concluding that the word useful is a mere redundancy of used .

Indeed, Pennsylvania is an especially clear example of a state in which investors have had explicit notice that neither recovery of prudent investment nor protection from substantial losses were part of any bargain on which they could rely. A string of court cases could not have been clearer:

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[12] Jersey Central Power & Light Co. v. FERC, 810 F. 2d 1168, 1181 n.3 (1987). Judge Starr concurring wrote "The prudence rule looks to the time of investment whereas the 'used and useful' rule looks toward a later time. The two principles are designed to assure that the ratepayers whose property might otherwise be 'taken' by regulatory authorities, will not necessarily be saddled with the results of management's defalcations or mistakes, or as a matter of simple justice, be required to pay for that which provides ratepayers with no discernible benefit...The 'used and useful' rule operates as a restraining principle, reminding utility managers of economic forces working against an investment which is prudent at the time it is made." at 1190.

[13] 488 U.S. 299 (1989). The Court noted that "... a rigid requirement for the prudent investment standard would foreclose a return to some form of the fair value rule just as its practical problems may be diminishing....The emergent market for wholesale electric energy could provide a readily objective basis for determining the value of utility assets." at 316.

[14] Philadelphia Electric Company v. Pennsylvania PUC, 61 Pa. Commw. 325, 328; 433 A.2d 620, 622-3 (1980). The Pennsylvania Supreme Court reached the same result in applying the used and useful rule to both Three Mile Island units, even though both had been in rate base and even though only one was destroyed in the 1979 accident, Pennsylvania Electric Company v. Pa. PUC, 59 Pa. 324, 334, 502 A. 2d 130, 135 (1985), appeal dismissed, 476 U.S. 1137 (1986).

- "It does not follow that a unit prudently constructed must always be included in rate base." Philadelphia Electric Company v. Pennsylvania Public Utilities Commission, 433 A2d. 620, 623 (Pa. Cmwlth, 1981), citing cases from 1952 forward.

- "We find no authority in Hope or other decisions, indicating that broad public interests are to yield to the interests of investors whenever the financial integrity of a utility company is imperiled ... It may simply be said that the utility has encountered one of the risks that imperil any business enterprise, namely the risk of financial failure. The express language of the Hope decision weighs against regarding utilities as a protected class of business enterprise which are to be relieved of such normal business risks ... If the Hope decision were to be interpreted as providing constitutional guarantees for the achievement of investor interests the "used and useful" principle would have to yield, at least in the situation where the financial integrity of a utility is imperiled, but we do not perceive from Hope that investor interests are to be accorded such a guaranteed status." Pennsylvania Electric Company v. Pennsylvania Public Utility Commission, 502 A2d 130, 134-136 (Pa., 1965), noting also that the U.S. Supreme Court had implicitly approved an identical result in declining to review Jersey Central Power & Light Co. v. Board of Public Utilities, 466 U.S. 947, 104 S.Ct. 2146, 80 L.Ed.2d 533 (1984) for want of a substantial federal question.

- "In the instant case, the Commission has interpreted the word 'useful' as requiring that: the plant and its associated capacity contribute no more than necessary to system reliability in the accepted, technical sense ... because we determine that the Commission's interpretation of the phrase 'used and useful' is a reasonable one, we will not overturn it ... the Commission determined that such a balancing of competing interests was fair, in that the risk of excess capacity is properly laid more heavily on PP&L's shareholders who voluntarily assumed that risk ..." Pennsylvania Power & Light v. Pennsylvania Public Utilities Commission, 516 A2d. 430-432 (Pa. Cmwlth., 1986).

Q. You indicated that investors could never have expected regulators to compensate them for losses due to competition. Please explain.

A. Investors have for many years been aware that no compact or other claim assures them of protection in the case of assets whose value is undermined by competition. As long ago as 1932, the Supreme Court warned that the Constitution does not assure to public utilities the right under all circumstances to have a return upon the value of the property so used. "The loss of, or the failure to obtain patronage, due to competition, does not justify the imposition of charges that are exorbitant and unjust to the public. The clause of the Constitution here invoked does not protect public utilities against such business hazards".[15]

Twelve years later, the Supreme Court sustained a decision of the California Commission to use as a rate base not the prudent investment in the Market Street Railway, but instead the price that the utility had asked of the city for its properties. In an opinion devoid of any discussion of stranded investment, exit fees or compacts, the Court wrote as follows about state-franchised utility assets whose value had diminished as a result of state-encouraged competition from state-built highways and streets, and state-certified taxis and trucks:

> The Due Process Clause has never been held by this Court to require a commission to fix rates on....an investment after it has vanished, even if once prudently made, or to maintain the credit of a concern whose securities already are impaired. The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.[16]

Q. Is there evidence in the last couple of decades that the financial community was aware that regulation would not guarantee investment value?

A. Yes, in fact there is considerable evidence to that effect. For example, burdened by power plant construction costs, Consolidated Edison Company of New York omitted its dividend payment in April, 1974. Leonard Hyman, former head of the utility research group at Merrill, Lynch, describes investor reaction as follows: "Con Edison's dividend omission hit the industry with the impact of a wrecking ball. It smashed the keystone of faith for investment in utilities: that the dividend is safe and will be

[15] Public Service Commission of Montana et al. v. Great Northern Utilities Co., 289 U.S. 130, 135 (1932).

[16] Market Street Railway Co. v. Railroad Commission of California et al, 324 U.S. 548, 567 (1944).This and the Montana case (n.14) are discussed in Phillips (supra, n.6,) at 381.

paid. Wall Street firms, at the behest of panic stricken clients, prepared lists that showed which utilities were in bad shape....Investors had to accept the possibility of financial risk in utility securities."[17]

A decade later Cincinnati Gas and Electric announced in October, 1983, that it could not afford to complete the Zimmer nuclear plant. Within twelve months, six utilities cut or omitted dividends, almost $6 billion of construction effort was consigned to oblivion, and the stock prices of the affected utilities fell 60-80% from their 1983 highs. According to Leonard Hyman, the message was clear. Utilities with serious problems caused by construction failures and *extreme cost overruns* would not be made whole by regulatory agencies. Investors could not depend on regulators for guaranteed returns or for bailouts.[18]

Q. Similarly, was there ever any evidence that a regulatory compact would protect investors from the effects of changing technologies that could render much or all of their investments obsolete and thus valueless?

A. No, quite the contrary. In fact, the foremost analyst of his day warned investors and utility executives of precisely what would happen if market prices fell below historic costs. James Bonbright foresaw precisely this turn of events with remarkable clarity and warned,

> "The second objection is that the original cost principle will be publicly rejected whenever, for reasons of price deflation or of technological progress, its maintenance calls for the establishment of rates of charge for service higher than current replacement cost...This objection runs to the effect that original-cost rate making is a deviation from competitive price determination popular with the consuming public only as long as the deviation is in their favor. But let reproduction-cost appraisals fall in the future....and the very persons who now so loudly

[17] Hyman, America's Electric Utilities, Past, Present and Future 3rd Ed. (Arlington, Va.: Public Utility Reports, 1988) p.109.

[18] Hyman, ibid, at 110-111. Furthermore, a municipal corporation, the Washington Public Power Supply System, defaulted on some $2.5 billion worth of revenue bonds establishing that even investments bakced up by actual contracts were not fully protected. Phillips, supra, pp. 681-2.

proclaim the fairness and efficiency of the actual cost tests will shift their position and demand that public utility rates be set free from the bondage of inflated historical costs. Those rare stalwarts who demand consistency even of themselves will be hopelessly outnumbered by newer experts, by more recently appointed commissioners, and by other persons not bound by embarrassing prior commitments....full recovery of the cost of old plant and equipment may be precluded by revolutionary developments in the technique of production, for example, in the field of {we must now break the prophetic spell} atomic energy" (parenthetical comment added)[19]

Those who argue that past investors could not foresee today's risks must somehow explain away the fact that Bonbright, probably the most-studied utility economist of the 1950s and 60s, warned of today's condition with great clarity. Yet, he does not describe that condition as a violation of a compact. Indeed, he mentions no compact to be violated. Instead, he prescribes as remedies "rapid cost recoupment in the form of liberal allowances for depreciation. As to any danger that may still remain, it can be and should be allowed for in the concession to public utility companies of 'fair rates of return' well in excess of interest on secure loans."[20]

The utility claim seems to be that they have an entitlement despite this history because the particular traumas of retail competition could not have been foreseen. As a factual matter, this claim is dubious, especially for PECO which has been alleging for many years that the risk of competition requires higher returns on equity.[21] Furthermore, the claim mocks the notion of risk, which is by its

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[19] Principles of Public Utility Rates (New York: Columbia University Press, 1961) at 188-89.

[20] Ibid at 189.

[21] Here, for example, is the testimony of Joseph Brennan of Associated Utility Services on behalf of Philadelphia Electric Company in a 1981 rate case in which the company's allowed return on equity was determined to be 17.75%: "There is a federal trend to foster competition in the utility business. The telephone and other industries engaged in communications....are some examples, and now there is talk of deregulation of electric generation. Deregulation...may increase risk", filed testimony, p.7. Larry Ruff of Putnam, Hayes and Bartlett told a 1989 electric utility Chief Executives' Forum, that the U.S. and Great Britain, are being driven by the same technological, economic and political forces towards a similar long run future: a competitive industry in which electricity is a commodity, much like any other.

nature not entirely foreseeable. The risk that generation costs would fall and that customers would find ways (including demanding governmental changes to the market structure) to take advantage are not risks from which utility investors have ever been entitled to complete protection. Electric utility investors have known for many years of the possibility of substantial losses, including bankruptcy. That these risks may have been greater than they perceived or have come from a different direction scarcely compels the imposition by regulators of an unconditioned strandable investment tax to assure full recovery.

C. Utility investors have been compensated for the risk of substantial loss.

Q. Have utility investors received returns on their investments well in excess of interest on secure loans?

A. Yes. The National Association of Regulatory Utility Commissioners publishes an analysis of utility shareholder returns. Here are some of the key findings from the latest edition:

1.) The common stockholders of 72% of all major electric and telecommunications utility companies earned a higher internal rate of return than did the average stockholder of the major non-regulated U.S. industrial corporations over the 21 year period 1972-1992....

2.) A second technique for determining the returns ... documents that 45% of electric and telecommunications utility companies earned a higher rate of return than did the average stockholder of the major non-regulated U.S. industrial corporations over the same 21-year period.

3.) A third method...shows that 73% of electric and telecommunications utility companies earned a higher rate of return than did the stockholders of the major non-regulated U.S. industrial corporations over the same 21-year period.[22]

In an Electricity Journal article reporting on an earlier edition of the same study, the authors conclude that individual investors have earned returns from electric utility common stock which exceeded those of non-regulated industrial corporations over the 17 year period 1972-1988.[23]

Q. Does this evidence support the contention that utility investors have been compensated for the risk of a substantial loss of their investments?

A. Clearly it does. If electric utilities have really outperformed industrial companies, whose investors clearly accept the risk of bankruptcy and adverse governmental action, then surely utility investors too have been compensated for the risk that some of their investment will be lost, by stranding or by some other means. This conclusion is reinforced by the fact that most utility stocks have traded significantly above book value for all or most of this era. This condition can only occur if they are earning in excess

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[22] Michael Foley and Ann Thompson, "Electric and Telephone Utility Stockholder Returns: 1972-1992" (Washington D.C.: NARUC, 1993), p. I.

[23] Foley and Thompson, "The Pains and Gains of Electric Utility Stock Ownership", Electricity Journal, June 1989, 28-35, 34. This article quotes John V. Cleary, then CEO of Green Mountain Power stating, "If you had invested $100 in utilities in 1955 and another $100 in a composite of industrials and reinvested all the dividends paid on both portfolios, the total pretax return in nominal dollars on your utility investment at year end 1986 would have been, you guessed it, greater than the return on industrials." at 29. Forbes Magazine is quoted as concluding that "Utility stocks have soundly beaten the market since 1975 - catching much of the street napping." at 29.

of their bare market cost of capital, i.e., in excess of the constraint to which they have ostensibly agreed as part of their obligation under the compact.

Q. Is this view shared by some in the electric utility industry?

A. Yes. For example, Wisconsin Electric CEO, Richard Abdoo, told the House Energy and Power subcommittee in July, 1994, "Our company has written off its uneconomic assets, so allowing others to recover stranded costs would penalize us." [24] A year later he was blunter still, "Stranded cost is a utility term. In economics it's called uneconomic assets. And in Economics 101 those sunk costs get written off. There's no rocket science involved." [25]

D. Not all strandable commitments were prudently incurred.

Q. Based on your experience as a regulator, is it reasonable to conclude that all investments made by utilities that are currently in rate base were prudently incurred?

A. No. For a variety of reasons, only a small percentage of the total utility rate base is ever actually reviewed for prudence. The discrepancies between the resources available to regulatory agencies and the revenue streams and construction budgets of utilities is so great that millions of dollars make their way into rates without serious scrutiny. That is one reason why most states put the burden of justifying even the existing rate level on the utility in any rate proceeding.[26] To believe that current rates at all

[24] Quoted by David W. Penn in Electricity Journal, December 1994, p.2.

[25] Energy Daily, December 4, 1995, p.4.

[26] For example, "...at any hearing involving a rate, the burden of proof... that the existing rate...is just and reasonable shall be upon the...utility...", New York Public Service Law, Section 72. Pennsylvania law is the same (66 Pa C.S.A. Section 315a).

times reflect prudent expenditures is to believe that the utility economizing of recent years somehow reflects efficiencies that reasonable managements could not have achieved sooner.

In many states, utilities use their considerable political involvement to harass regulatory budgets and appointments in a manner hardly consistent with a statesmanlike compact. Those usually among the first to assert and assist the shortcomings of regulation seem unashamed to assert its perfection in having measured past prudence.

Q. What is the consequence of assuming that all of a utility's rate base has been prudently incurred?

A. The most obvious consequence is to accord unwarranted validity to a utility's claim that it is entitled to recovery of its prudently incurred stranded costs. Because much of these costs have never been subjected to thorough review and scrutiny by the regulators and ratepayers, current utility estimates of total stranded costs are likely to be higher than they should be. If these costs are securitized, as proposed by PECO, it will be very difficult if not impossible to ever subject them to further prudency review.

E. Conclusion

Utilities sometimes argue that until full strandable investment recovery is assured, they must slow the pace of restructuring, thereby deferring the benefits of competition. Others too advocate paying them off first and negotiating about everything else afterwards.

This approach to negotiation was lastingly discredited at Munich. Utility resistance to many desirable changes in industry structure has already manifested itself. It will not go away if the companies are guaranteed strandable investment recovery. Instead, market power problems, to name an obvious example, will further delay the benefits of competition through long and litigative years. The way to be sure that stranded investment recovery expedites real competition is to condition such recovery as is allowed in ways that keep the incentives on the side of the public.[27]

A decision to allow stranded investment recovery is a social policy decision, as surely as is a renewable portfolio requirement or a lifeline program or an economic development rate. Indeed, the decision to allow a lost revenue adjustment and performance incentives in the context of utility DSM programs was a similar linkage of shareholder well-being to the achievement of larger societal ends.

The stakes are larger here. The decisions are more complex, and far more dust is being thrown in the regulators' eyes.

Nonetheless, the bottom line is clear enough. Strandable investment is the public's best leverage to an effectively competitive and an environmentally acceptable future.[28] Regulators, legislators and others in the public sector must not give it away until that future is well secured.

[27] Strandable investment is in any case connected to market power. An impaired market structure will tend to raise market prices, thereby lowering strandable investment. Therefore, a utility seeking to maximize the portion of its investment recoverable under the relative security of a stranded investment charge must cooperate in maximizing the effective operation of market forces.

[28] New York PSC Chairman John O'Mara made this point in a July 24, 1995, letter to NARUC president Bob Anderson, stating, "Without full authority to establish the extent (of) and conditions upon utility investments to provide public service the states will lose the leverage required to achieve (a) competitive electric market."

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIVED
JUN 19 1997
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DOCKET NO. R-00973953

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER
SECTION 2806 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY OF

RICHARD H. SILKMAN

FILED ON BEHALF OF

*** THE OFFICE OF STATE SENATOR VINCENT J. FUMO ***
*** CEPA ***
*** ACORN ***
*** TENANT ACTION GROUP ***
*** ACTION ALLIANCE OF SENIOR CITIZENS ***
*** JOHN W. LONG, JR. ***

DOCKETED
JUN 25 1997

JUNE 20, 1997

DIRECT TESTIMONY OF
RICHARD H. SILKMAN

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DIRECT TESTIMONY OF
RICHARD H. SILKMAN

Qualifications

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Richard H. Silkman, 76 Main Street, Yarmouth, Maine, 04096.[1]

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL EXPERIENCE AND PRIOR WORK BACKGROUND.**

A. I have served on the faculties of the State University of New York at Stony Brook (1978-1983) and the University of Southern Maine (1983-1986), where I also served as the Acting Director of the Public Policy and Management Program (1986). I was appointed by Governor John R.McKernan to become the Director of the Maine State Planning Office (1987-1992), a cabinet level agency with broad policy and planning responsibilities, including economic development, energy, taxation, budgets, land-use management and health care. In this capacity, I chaired a number of state level committees and multi-agency task forces and was on the Board of Directors of a variety of quasi-governmental agencies including the Maine Development Foundation, the Maine Science and Technology Commission and the Maine World Trade Association. I also chaired a number of Staff Advisory Committees of the National Governors' Association, including its Task Force on Health Care (1989-90), Telecommunications Committee (1987-88) and Human Resources Committee (1990-91).

I have been a member of the Board of Directors of the Council of Governors' Policy Advisors (CGPA), an affiliate of the National Governors' Association (1988-92), and its President (1990-1991). I have an undergraduate degree in economics (with honors) from Purdue University (1972) and a Ph.D. in economics from Yale University (1980).

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[1] My previous address was 163 Main Street. Our town's street numbering has been changed to accommodate a new E-911 service.

Q. PLEASE DESCRIBE THE NATURE OF YOUR CURRENT CONSULTING ACTIVITIES.

A. I serve as a consultant on energy matters for a variety of clients in Maine and the northeast. These clients include a trade association of Maine's largest industrial consumers of electricity, a Fortune 500 multi-state retail grocery company, and a municipal water district. In representing these clients and others, I have negotiated over a dozen special electric rate contracts with investor owned public utilities and have testified before the Maine Public Utilities Commission on matters of rate design, the justness and reasonableness of rates and electric utility industry restructuring.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITIES COMMISSION?

A. Yes. I filed joint testimony with Peter Bradford on behalf of the same clients in PECO's application for approval of its securitization proposal.

Purpose and Scope of Testimony

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A. I have been retained by CEPA, Tenant Action Group, ACORN, Action Alliance of Senior Citizens and John W. Long, Jr. and the Office of State Senator Vincent J. Fumo:

a. To perform an economic impact analysis of PECO's proposed restructuring plan and to contrast the impact of this plan with other proposals designed to make electric rates for PECO's customers competitive with other electric rates in the region and country.

b. To evaluate whether the restructuring plan proposed by PECO will create fully competitive retail electricity markets.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Yes. My conclusions are as follows:

First with respect to the economic impact of PECO's proposed restructuring plan:

- PECO's proposed restructuring plan will do little to lower electric rates within its service territory, and what rate reductions that may occur will be the result of securitization of stranded costs. Customers will continue to face electric rates that are above those offered by other utilities in the mid-Atlantic states and well above the national average.

- The continued high electric rates will impose an economic cost on the region over the next ten years in terms of lost job opportunities, disposable income, private investment and tax revenues.

- Specifically, if restructuring results in a reduction of PECO's electric rates by 12%-18% to the average rates charged by neighboring utilities, the lower rates would generate between 8,000 and 10,000 new jobs over the next decade.

- Further, if rates were lowered to the national average (a reduction of 30%-40%), an estimated 21,000 additional new jobs would be created, and total disposable income in the five-county region served by PECO would increase by between $1.015 and $1.63 billion a year, resulting in an additional $125 to $200 million a year in state sales and income tax revenues.

Second, I do not believe that PECO's proposed restructuring plan accomplishes the General Assembly's intent of ensuring that the retail market for electricity is a fully competitive market and that the benefits of competition are available to all customers. Specifically,

- PECO's proposal regarding the computation of market value of its physical generating assets coupled with the full recovery of stranded costs creates a competitive advantage for PECO that may discourage competitors from entering the market, thereby reducing the choice available to consumers and the overall competitiveness of the retail electricity market.

- PECO has reserved for itself the ability to establish unregulated competitive generation provider and marketing services through affiliates within the geographic region served by the PJM pool and by PECO's local distribution utility ("LDU"). This creates a financial incentive for PECO to use its monopoly position to the advantage of its affiliates by shifting costs onto captive customers and increasing returns to shareholders by enhancing the profitability of the affiliates.

- The manner in which PECO proposes to carry out its statutory obligation to serve as a provider of last resort under Section 2802 (16) and Section 2807 (E)(1) of the Competition Act may deny those customers who do not select alternative providers the full benefits of competition. These customers would be better off if PECO competitively bid the provision of energy to these customers.

- PECO has proposed to retain exclusive right to provide meters and meter reading services for all customers. There is no satisfactory reason why these non-monopolistic services must continue to be provided by PECO. Further, by restricting who can offer these services, PECO is providing a competitive disadvantage to its competitors who may be forced to install and pay for parallel metering systems to support the energy services and products they offer their customers.

- The recovery of stranded costs through *securitization* ("Intangible Transition Charges") gives PECO an advantage over potential competitors by permitting it to enter the competitive market with a significantly reduced debt position and with cash in hand. As noted above, this will discourage other competitors from entering this market and diminish the potential benefits from competition.

Economic Impact Analysis

Q. IN PERFORMING THE ECONOMIC IMPACT ANALYSES, DID YOU DEVELOP AN ECONOMIC MODEL FOR THE PECO SERVICE TERRITORY?

A. No. I did not develop such a model. Instead, I utilized a specific locational variant of the general REMI EDFS-53 Forecasting and Simulation Model developed by Regional Economic Models, Inc. ("REMI") of Amherst, Massachusetts. REMI constructed this model for the five-county region comprising PECO's electricity service territory. These counties are Bucks, Chester, Delaware, Montgomery and Philadelphia.

Q. WHY DID YOU SELECT THIS MODEL?

A. I elected to use the REMI model for a number of reasons. First, I am very familiar with the structure and performance of REMI models. During my tenure as the Director of the Maine State Planning Office, we utilized a statewide REMI model of the Maine economy to analyze the economic consequences of a wide variety of major economic events. These included a proposal by Maine's largest electric utility to enter into a long-term power purchase contract with Hydro Quebec, proposed legislation designed to achieve significant reductions in the cost of workers compensation coverage, the closure of a major Air Force base in northern Maine and legislation proposed to increase the State's minimum wage. In addition, we used the REMI model to perform long-term forecasts for Maine's economy and to analyze the consequences of various economic scenarios on the State's labor market, job training programs and tax base.

Second, the REMI model has developed a national track record and in the process has demonstrated its usefulness in a broad spectrum of policy areas and geographic regions of the country for a client base that includes state governments, planning agencies, universities, utility companies[2] and private consulting firms. In fact, the REMI documentation for the model includes a sample list of recent applications, some of which I have included in Exhibit SILKMAN-1.[3]

Third, the REMI model incorporates a number of useful features that make simulation of alternative scenarios possible. For example, in the REMI EDFS-53 model, there are over 1,000 regular economic policy variables that can be used singly or in combination to simulate the economic and demographic consequences of changes in factors that may affect the final demand for goods and services, in factors that may affect population, labor force and migration, in factors that may affect imports and exports in the aggregate, by industry or by economic sector and in factors that may affect the cost of production such as wage rates, fuel or electricity costs and taxes. Finally, the REMI model permits the user to specify how much detail is to be presented in the output of simulations. The user can examine simulation results of the REMI EDFS-53 model for over 2,000 economic variables and several hundred demographic variables. For example, the model computes the effects for 53 industrial sectors (including government) and up to 94 occupational categories.

Q. PLEASE DESCRIBE HOW YOU SIMULATED THE ECONOMIC IMPACT OF PECO'S PROPOSED RESTRUCTURING PLAN USING THE REMI MODEL.

A. The REMI model incorporates a "base case", defined as the estimated forecast of the region's economy assuming no significant changes occur that would affect major policy variables. A selection of results from the base case are provided in Exhibit SILKMAN-2. Note that in the base case, electricity prices are forecasted to increase at the same rate as the national average; thus,

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[2] A variant of the REMI model was recently used by a division of NEPOOL in estimating the long-term impacts of restructuring New England's electric industry. As I note later in my testimony, the results obtained in that analysis are very similar to those I present here for PECO. See, "Long-Term Economic Impacts of a Restructured New England Electric Utility Industry," NEPLAN Economic & Load Forecasting Staff, March, 1997.

[3] It is interesting to note that the first illustrative simulation presented in the REMI Reference Set and User's Manual is the effect of a 10% increase in electric cost for the industrial and commercial sectors in Massachusetts.

relative to the U.S. as a whole, electricity rates remain constant.[4] It is important to remember that the absolute values of the forecast results are less important in using the REMI model, since the simulations focus on <u>differences</u> from the base case and not on the actual forecast values. This is in contrast to pure forecasting models, where the forecasted values of economic variables such as interest rates, employment, income growth, etc. are of interest.

PECO's proposed restructuring plan does not anticipate any reductions in electricity rates, but is rather designed to permit PECO to operate within the rate cap established by the Electricity Generation Customer Choice and Competition Act (the "Competition Act" or the "Act"). To estimate the rate impacts of PECO's proposed restructuring plan, I assumed that PECO would be able to achieve rate reductions relative to national electricity rates comparable to what the Company proposed in its request to securitize a portion of its estimated stranded costs in its previous securitization application. In that request for securitization, PECO projected potential rate reductions of approximately 3% from securitizing $3.6 billion of stranded costs. I used this estimated rate reduction as the effect of the proposed restructuring plan and applied it to electric rates in each year of the forecast or study period[5], beginning in 1998. The effect of this is to reduce the ratio of electricity rates for PECO customers versus for the nation as a whole relative to the ratio in the base case.

The results of this forecast are presented in Exhibit SILKMAN-3. This exhibit follows the same format as the previous exhibit, except that the figures represent changes from the base levels presented in Exhibit SILKMAN-2. As illustrated, PECO's proposed restructuring plan does result in small incremental impacts flowing from the rate reductions achieved through securitization.[6] Under the PECO plan, between 1,200 and 1,600 additional jobs will be created

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[4] The base forecast included in the REMI model does not factor in the effects of the recently enacted Electricity Generation Customer Choice and Competition Act (the "Competition Act" or the "Act"), specifically the provisions in Section 2804 of the Competition Act which impose a rate cap on electric rates for up to nine (9) years. To the extent that electricity prices increase nationally over the next ten years, the Act would have the effect of lowering relative prices in the PECO service territory. This could be expected to have a positive economic impact in the five-county region.

[5] I have chosen a forecast or study period of 10 years to be reasonably consistent with the periods specified in the Act. Thus, the study period runs from 1998 through 2008. I have begun the study period in 1998 rather than in 1997 to reflect the start-up delays inherent in administrative and legal proceedings.

[6] Since the Pennsylvania Public Utilities Commission approved only $1.1 billion of PECO's request and since PECOhas not amended its restructuring plan to request securitization of the balance of $2.5 billio, the

over the study period, as well as $75 to $125 million in additional disposable income and an estimated $9 to $15 million in combined state sales and personal income tax revenues.[7]

Q. PLEASE DESCRIBE WHY THESE RESULTS OCCUR, I.E., WHY ELECTRICITY RATE REDUCTIONS GENERATE ADDITIONAL JOBS, NEW INVESTMENT, INCREASES IN DISPOSABLE INCOME AND ADDITIONAL TAX REVENUES.

A. Economic theory tells us that changes in the price of any good or service create two consumer responses – a price and an income effect. The price effect measures how a consumer's consumption of the good or service changes as the price of that good or service changes. The income effect is less direct. It derives from a change in the level of disposable income that is created when the price of any particular good or service changes. Thus, if the price of electricity declines, for example, a consumer will respond by purchasing more electricity as a result of the price effect, and more of all other goods and services (including electricity) as a result of the income effect.[8]

The total price effect can be broken down into different components. These include to varying degrees the following:

a. Residential consumers will use more electricity as a result of being less concerned about the price they must pay per unit of consumption. They may turn up thermostats, leave lights

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estimated 3% reduction may be overstated and the estimated economic impacts of PECO's proposed restructuring plan would be too large.

[7] The tax impacts do not include revenue losses or gains from the gross receipts tax on electric bills. Section 2810 (A) of the Act states,

> "It is the intention of the General Assembly that the restructuring of the electric industry be accomplished in a manner that allows Pennsylvania to enjoy the benefits of competition, promotes the competitiveness of Pennsylvania's electric utilities and maintains revenue neutrality to the Commonwealth. ... It is the intention of the General Assembly to establish this revenue replacement at a level necessary to recoup losses that may result from the restructuring of the electric industry and the transition thereto."

I have assumed that the mechanism to accomplish this objective that is set forth in the remainder of Section 2810 of the Act is successful in achieving revenue neutrality, and therefore I have not considered any revenue consequences with respect to the gross receipts tax.

[8] This assumes that all goods and services are "normal" goods and thus have positive income elasticities. It is possible that certain goods or services have negative income elasticities such that consumption decreases as income increases. This category of goods and services may include such things as public transportation and generic brands where substitutes of higher quality are available and to which consumers move as their incomes increase.

on for longer periods, install additional lighting, purchase additional electric appliances or switch from non-electric to electric technologies for such things as space or water heating.

b. Commercial customers may respond in a manner similar to residential consumers. In addition, commercial consumers may increase the square footage, the hours and/or the methods used in their operations, thus increasing electric consumption. Further, lower electricity prices may induce certain commercial consumers to open new or relocate existing facilities to the region where electricity prices have fallen, and may induce some consumers to change plans and remain in the region rather than to leave for lower cost areas. All of these effects would also increase electricity consumption.

c. Industrial consumers may respond to reductions in electricity prices in all of the same ways as residential and commercial consumers. In addition, industrial activity may be retained within the region as a result of falling electricity prices, thus resulting in higher levels of electricity consumption than would have occurred otherwise.

d. Other consumers such as municipal governments may also respond to lower prices by increasing consumption by, for example, installing additional street lighting or leaving the street lighting on for longer periods of time.

In all of the above situations, the increase in electricity consumption will have secondary impacts in the economy. Business retentions, expansions or relocations will increase overall economic activity within the region and in the process generate additional employment opportunities as well as increases in disposable income. Further, to the extent that consumers respond to the lower electricity prices by changing technologies or making related expenditures, economic activity will increase.

The income effect will operate on all consumers in much the same manner as these latter impacts. Increases in disposable income will be spent throughout the economy on a wide range of goods and services, thus generating new economic activity and consequent increases in jobs. While generally we tend to think of the income effect as being relatively small, for electricity on a regional basis and in the aggregate, it could be very substantial. For example, in 1996 residential consumers spent approximately $1.1 billion for electricity from PECO. A 10% reduction in the price of electricity would result in a direct increase of approximately $110 million in disposable income for residential consumers in the five-county region. This is roughly the equivalent of the direct purchasing power that would be injected into the regional economy by a new corporation locating in the region that employs 2,200 workers with an average annual salary of $50,000.

Of course, both the direct price and income effects described above, each have associated with them indirect effects as consumers' initial responses to the price reduction are "multipled" as they work their way through the economy. The total effects are then defined as the sum of the direct price and income effects plus their respective indirect or "multiplier" effects.

Q. ARE ALL OF THESE EFFECTS CAPTURED BY THE REMI MODEL SIMULATIONS?

A. The REMI Model is designed to capture and measure the sum of all of these effects. In practice, however, the relationships among all of the sectors of the economy and the individual actions of all of the consumers in the economy are so complex that no economic model can be said to capture fully all of these effects. The REMI Model, however, is among the more sophisticated of the available models and is generally regarded as state-of-the-art in terms of its ability to approximate the behaviors and interrelationships that exist in a regional economy.

Q. DID YOU PERFORM ANY OTHER SIMULATIONS TO FORECAST THE IMPACTS OF ALTERNATIVE RESTRUCTURING PLANS FOR PECO THAT WOULD RESULT IN DIFFERENT PERCENTAGE REDUCTIONS IN ELECTRIC RATES?

A. Yes. I developed four additional scenarios for rate reductions that relate to different percentage reductions in electric rates for PECO customers and simulated the imposition of these reductions in the five-county region served by PECO using the REMI Model. The four scenarios developed are:

1. An across-the-board flat 10% reduction in electric rates for all classes of customers throughout the study period. In this scenario, consumers see average prices for electricity that are 10% lower than under the base case.
2. An immediate reduction to the regional average rate levels for each customer class. These immediate rate reductions are retained for the duration of the study period.
3. An immediate reduction to the national average rate levels for each customer class. These immediate rate reductions are retained for the duration of the study period.
4. A gradual phase-in of rate reductions designed to achieve rates equal to the national average by the end of the study period. This phase-in begins with an immediate 10% rate

reduction for each class of customers. Subsequent rate reductions are designed to close the gap between these new PECO rates and the national average rates for each class in a linear fashion.

Q. HOW WERE THESE SCENARIOS SELECTED?

A. These scenarios were selected in part to illustrate a variety of potential impacts that could be achieved through the adoption of restructuring plans for PECO that result in more significant rate reductions than those implicit in PECO's own proposed restructuring plan. The first of the four scenarios is a useful one, since it illustrates the consequences of a general across-the-board reduction in rates, and can be compared to a similar but less substantial reduction provided for under PECO's proposed restructuring plan. While the REMI Model is not necessarily a linear model, i.e., the results of a 20% reduction in electric rates will not necessarily be twice those of a 10% reduction, the results tend to be approximately proportional over relatively small ranges of policy input value. Thus, the interested reader could approximate alternative rate reduction scenarios by applying different scale factors to the results of the first scenario.

The second and third scenarios were selected to be responsive to the findings of the General Assembly as set forth in Section 2802 (4) and (7). Subsection (4) finds that "Rates for electricity in this Commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities." In this declaration, the General Assembly has identified two relevant benchmarks for the reasonableness of PECO's electric rates – the national average and the average of electric utilities serving portions of the Commonwealth. Subsection (7) provides the rationale for these benchmarks,

> "This Commonwealth must begin the transition from regulation to greater competition in the electric generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs."

I believe that these declarations of findings and policy establish as policy goals rates equal to the regional[9] and national averages, respectively, for all customer classes, subject to the other

[9] In computing the regional average electric rates, I used information provided by PECO in its response to OCA-IX-18. The list of utilities included in the rate comparison provided by PECO in this response is not a complete list but was chosen because it appears to reflect the utilities that PECO tracks and thus considers as useful benchmarks and also its most significant potential competitors.

considerations expressed in Section 2802, e.g., health and safety, system reliability, equity of impacts on all parties, etc.

The actual calculations for these two scenarios (as well as the fourth scenario) are presented in Exhibit SILKMAN-4. Each of these scenarios targets a specific benchmark electricity rate in order to reduce the economic disadvantages that PECO's customers currently face vis a vis counterparts in their region and in the country as a whole.

The fourth scenario is similar to the third scenario in terms of the objective at the end of the study period, except that it provides for a more gradual transitioning process in the interim. The initial rate reduction of 10% was selected largely because of the "currency" this figure appears to have as a target in state restructuring programs that have been implemented in Massachusetts and California, for example.

Q. PLEASE DESCRIBE THE RESULTS OF THE FORECASTS UNDER EACH OF THESE SCENARIOS.

A. The results of the four scenarios are presented in Exhibit SILKMAN-5, using the forecast results from the base case (see Exhibit SILKMAN-2) as the point of reference. Thus, each of the results should be interpreted as the change (either increase or decrease) in the value of that indicator in comparison to its forecasted value in the base case, i.e., it is the incremental benefit (cost) that would be created by the adoption of a restructuring plan that results in the rate reductions contained in each scenario. If the impacts of the PECO case from Exhibit SILKMAN-3 are subtracted from each set of results, the difference can be thought of as the "opportunity cost" of adopting PECO's proposed restructuring plan.

The results demonstrate a very clear pattern that is consistent with what one would expect – the larger the rate reductions, the more substantial the economic impacts. The results of these simulations can be put in perspective by observing that scenarios two and three effectively undo the rate increases experienced by PECO's customers during the late 1970s and 1980s. These rate increases have created the cost differentials between PECO and its regional peer group and between PECO and the national average. Thus, to the extent that the slower growth experienced by the five-county region served by PECO is the result of higher electricity costs during this period, the opposite effects can be expected to occur during the study period as electricity rates are reduced to benchmark levels.

An immediate rate reduction to the national average would have the most profound effects. This scenario generates 17,202 additional jobs in 1998, with this number increasing to 21,561 new jobs by 2008.[10] It also results in gains in total disposable income of $1.015 billion in 1998 increasing to $1.63 billion by 2008 and an additional $124 million to $200 million in Pennsylvania state income and sales tax revenues over the study period. Further, the rate reduction will generate an increase in investment activity in the region, which, in turn will be responsible for increasing property tax revenues at the municipal level.[11]

Less substantial rate reductions that would bring PECO rates in line with the regional average also result in significant economic benefits within the region. As shown in Exhibit SILKMAN-5, this scenario would create between 8,000 and 10,000 new jobs and increase disposable incomes in the region by $465 million in 1998 and by $722 million by the end of the study period.

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[10] It is interesting to contrast this estimate with two estimates that have been made for a similar scenario for the New England region. The New England Economic Project ("NEEP") in conjunction with Regional Financial Associates of West Chester, PA estimated that a reduction in New England's electric price disadvantage vis a vis the nation from 50% to 17% as a consequence of industry restructuring would generate an additional 225,200 new jobs or about 2.8% more than would exist without restructuring. See "The Economic Outlook in a World of Deregulating Industries," prepared for the New England Economic Project by Regional Financial Associates, West Chester, PA, October 1996.

The second study was referenced earlier and was done by NEPLAN, a division of the New England Power Pool ("NEPOOL"). That study used the REMI model to estimate the economic impacts of a reduction in New England and national electric prices of 40% and 20%, respectively. The NEPLAN analysis showed an increase of approximately 100,000 new jobs or roughly 1.3% on the base of 8 million. My estimates are actually less aggressive than the NEPOOL estimates, as my forecast is for an increase of about 1% in total new jobs created. See "Long-Term Economic Impacts of a Restructured New England Electric Utility Industry," NEPLAN Economic & Load Forecasting Staff, March 1997.

[11] The property tax figures are not computed by the REMI Model for single-region models below the state level of aggregation. I have not attempted to estimate property tax consequences for two reasons. First, the REMI Model does not provide sufficient disaggregation of private investment to account for such factors as tax exempt status for certain types of investment and for depreciation. Second, the Model does not provide intra-regional locational information. Thus, it is impossible to match new investments with effective property taxes in each taxing district, nor to incorporate such factors as municipal zoning into the analysis. Since there is generally substantial variability within economic regions in effective property tax rates across municipalities and in the degree to which they permit different types of economic activity, using the average effective property tax rate may not provide an accurate estimate of total tax yields.

Finally, a phased reduction in rates to the national average over the study period would generate increasing economic benefits as the rate decreases are phased in. It is interesting to note that, under this scenario by the end of the study period, the benefits would not be quite as large as under scenario three (immediate rate reduction to the national average) even though the rates under these two scenarios are equal by the end of the study period. This is because the REMI Model incorporates adjustment mechanisms and feedback effects that trace the immediate impacts of policy variable changes through the economy over a period of time. Under scenario three, the immediate reduction in rates occurs in the first year and thus the full effects are felt by the end of the study period. In contrast, the phased decreases in rates under scenario four spread out the full effects of the reductions in the latter years of the study period to the time beyond the end of the period.

The job creation impacts of the five scenarios are shown graphically in Exhibit SILKMAN-6. As noted earlier, the difference between each scenario and the PECO proposal represents job opportunities foregone by the adoption and implementation of PECO's proposed restructuring plan. As is evident from the graph, adoption of the PECO proposal would come at a very high opportunity cost in terms of lost jobs, jobs that would be created under restructuring plans that incorporate more aggressive electricity rate reductions.

Impact on Competitive Electricity Markets

Q. WHY IS IT IMPORTANT THAT ANY RESTRUCTURING PLAN ADOPTED BY THIS COMMISSION ENSURE THAT THE RESULTING RETAIL MARKET FOR ELECTRICITY IS COMPETITIVE AFTER RESTRUCTURING OCCURS AND RETAIL ACCESS IS PERMITTED?

A. There are a number of reasons why the Commission should ensure that retail markets for electricity are fully competitive. First, the General Assembly stated very clearly and without equivocation in Section 2808 (5) of the Electricity Generation Customer Choice and Competition Act that it finds and declares "Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity." To emphasize the critical nature of the establishment of competitive retail electricity markets, the General Assembly directed the Commission, in response to "good cause", to conduct investigations whenever anticompetitive or discriminatory conduct affects the retail distribution of electricity and therefore may "impact the proper functioning of a ***fully*** competitive retail electricity market." (Section 2811 (B) – emphasis added.)[12]

Second, the Competition Act deregulates the generation of electricity and the sale of electric capacity and energy at retail. While the expectation is that competitive market forces will quickly and completely dominate this newly deregulated market, the current market structure is far from competitive, and vestiges of this current market structure will continue after deregulation has occurred. If restructuring plans do not deliberately and explicitly set forth conditions governing the relationships between the current and new market structures, it is likely that continuing aspects of the current market structure will influence behavior in the deregulated market at the expense of competition.

Third, many electricity consumers and especially residential and small commercial consumers remain unaware of or do not understand the opportunities that will arise and the risks they may face in a deregulated retail electricity market. To some extent, the General Assembly has anticipated some of these risks in establishing duties and requirements for electric distribution companies (Section 2807) and electric generation suppliers (Section 2809). What is less clear and what may have important consequences for the establishment of retail electricity markets is how electric distribution companies fulfill their continuing obligation to serve during the "transition period" under Section 2807 (E) (1) which states "the electric distribution company shall continue to have the full obligation to serve, including the connection of customers, the delivery of electric energy and the production and acquisition of electric energy for customers."

Q. ARE THERE COMPONENTS OF OR OMISSIONS IN PECO'S PROPOSED RESTRUCTURING PLAN THAT MAY REDUCE THE LIKELIHOOD THAT THE RETAIL ELECTRICITY MARKET IN ITS CURRENT SERVICE TERRITORY WILL BE FULLY COMPETITIVE AFTER RESTRUCTURING OCCURS?

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[12] Elsewhere in Section 2811, the General Assembly directs the Commission to regulate the activities of companies operating in the market or refer its findings to the Attorney General, the United States Department of Justice, the Securities and Exchange Commission or the Federal Energy Regulatory Commission where it finds that these activities prevent or inhibit consumers from realizing "the benefits of a properly functioning and workable competitive retail electricity market."

A. Yes. There are five (5) areas in particular where I believe that PECO's proposed restructuring plan is not consistent with the General Assembly's intent that the retail electricity market after restructuring become a fully competitive market. These areas are:

1. The computation of market value of existing physical generating assets and the full recovery of stranded costs.
2. The ability to establish unregulated competitive generation provider and marketing services through affiliates within the geographic region served by the PJM pool, generally, and by PECO's local distribution utility ("LDU"), more specifically.
3. The manner in which PECO proposes to carry out its statutory obligation to serve as a provider of last resort under Section 2802 (16) and Section 2807 (E)(1) of the Competition Act.
4. PECO's proposal to retain exclusive right to provide meters and meter reading services for all customers.
5. The recovery of stranded costs through securitization and "Intangible Transition Charges" which give PECO an advantage over potential competitors by permitting it to enter the competitive market with a significantly reduced debt position and with cash in hand.

Q. **PLEASE DESCRIBE HOW PECO'S PROPOSAL REGARDING THE COMPUTATION OF MARKET VALUE OF GENERATING ASSETS AND THE FULL RECOVERY OF STRANDED COSTS MAY IMPACT THE DEVELOPMENT OF A FULLY COMPETITIVE RETAIL ELECTRICITY GENERATION MARKET.**

A. As described by Mr. Hill in his Direct Testimony, PECO retained the services of three independent experts to estimate the net market value of its existing generating assets. These experts developed different estimates based on different assumptions and methodologies, the average of which equals \$3.3 billion. Despite the fact that two of the estimates were \$3.65 billion and \$3.49 billion, PECO elected to use the lowest estimate of \$2.86 billion.

The use of the lowest of the three estimates has two effects. First, it increases the amount of stranded costs that PECO seeks to collect from ratepayers through either a Competitive Transition Charge ("CTC") or an Intangible Transition Charge ("ITC"). This raises equity concerns, but should have minimal effects on the competitiveness of the retail generation market. The second effect is that PECO's choice lowers artificially the "economic cost" of PECO's generating assets, thereby enabling PECO to price their electricity outputs more competitively (approximately 10% below estimated market prices) in the marketplace.[13] This kind of a competitive advantage, especially when it accrues to the incumbent utility, may discourage competitors from entering the market thereby reducing the choice available to consumers and the overall competitiveness of the retail generation market.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS PROBLEM?

A. I have not performed a study of the net economic value of PECO's generating assets and thus cannot comment on the relative accuracies of these estimated values presented by PECO or on the estimates presented by other intervenors in this case. I believe, however, that in the presence of conflicting evidence the Commission should act conservatively by choosing from among the high range of such estimates in order to stimulate competition in the retail generation market. This will ensure that the full benefits of any unrealized efficiencies in the operation of PECO's generating units not captured by historical performance will accrue to customers in PECO's current service territory rather than PECO's shareholders, and further that competitors will not be discouraged from entering the generation market as a result of an artificial competitive advantage given to PECO through the restructuring process. This approach is not an unreasonable one considering the inherent uncertainty in the projections used by all of the parties in developing estimated market values for generating assets.

Q. PLEASE DESCRIBE YOUR SECOND CONCERN THAT THE ABILITY TO ESTABLISH UNREGULATED COMPETITIVE GENERATION PROVIDER AND MARKETING SERVICES THROUGH AFFILIATES WITHIN THE GEOGRAPHIC REGION SERVED BY THE PJM POOL, GENERALLY, AND BY PECO'S LOCAL DISTRIBUTION UTILITY ("LDU"), MORE SPECIFICALLY, MAY IMPACT THE COMPETITIVENESS OF THE RETAIL ELECTRICITY MARKET.

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[13] The cost advantage may be substantial. The $800 million lower market value of Dr. Hieronymous versus Mr. Bustard, for example, translates into an annual cost savings of about $111 million, computed based on 11% captial cost and a 15 year amortization period. Using the total output of these units in 1996 as reported in PECO's FERC Form 1 of 34,717,625 MWh, the savings is approximately $3.20 per MWh. This represents a little less than 10% of the estimated market value of electricity as estimated by all three of PECO's experts.

A. The General Assembly, in anticipation of concerns over the discriminatory use of the monopolistic transmission and distribution network that continues to be owned and operated by PECO after restructuring, established among its standards for restructuring in Section 2804 (6) that:

> "The Commission shall require that a public utility that owns jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperatives and electric generation suppliers, affiliated and nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system."

This type of provision is necessary only to the extent that PECO is permitted to operate as a regulated monopoly with respect to the provision of transmission and distribution services and simultaneously as a competitor in the provision of energy in a competitive marketplace. In this case, PECO has a clear financial incentive to use its monopoly position to the advantage of its unregulated affiliate(s) by shifting costs onto the captive customers of the monopoly LDU and increasing the returns to shareholders by enhancing the profitability of the affiliate(s).[14]

In addition, the LDU has the financial incentive to ensure that services provided by its unregulated affiliate are given highest priority with respect to the transmission and distribution network. As noted in a recent report prepared by the staff of the Virginia State Corporation Commission,

> "Notwithstanding regulation, a utility may still have a competitively significant, although not unconstrained, ability to reduce the availability and reliability of transmission service, increasing the price of such service. A utility may limit the availability of transmission service to competitors in numerous ways. It may decide to change (or not change) the output levels of its generators, to leave a low-voltage line connected, or to limit supplies of reactive power in order to constrain the amount of transmission capacity available to competitors. It may also delay repairing or expanding transmission facilities, prolong maintenance outages or schedule maintenance outages during critical periods. In addition, it may engage in power sales that create loop flows that foreclose transmission service in another corridor. In addition to

[14] It should be noted that this concern is not restricted to the electric utility industry. In a recent speech by Robert Allen, the Chairman of AT&T, Mr. Allen indicated that AT&T's efforts to enter local phone markets have been stymied by resistance from Baby Bell "monopolies." Allen said Baby Bells were stifling true competition by slowing AT&T's orders, and in California such slowdowns have forced AT&T to stop marketing its local service. According to Mr. Allen, despite AT&T's expenditure of over $1 billion, it has been unable to secure reasonable terms and conditions from local telephone monopolies to permit AT&T to offer service in competition with these monopolies. Those who understand the history of telephone deregulation will appreciate the irony of Mr. Allen's remarks. That one of the largest and wealthiest companies in the world can be so thwarted in its efforts is testament to the market power inherent in a regulated monopoly. (Richard Lorant, Associated Press, in Portland Press Herald, June 11, 1997.)

preventing specific sales by competitors, even occasional actions of these types may be used to undermine a competitor's reliability as a supplier. Therefore, utilities may be able to reduce the availability of transmission capacity for use by competitors that the FERC cannot effectively regulate."[15]

PECO has acknowledged this concern and has attempted to address it through the voluntary adoption of a "code of conduct" governing relationships between the LDU and any unregulated affiliates.

Q. DO YOU BELIEVE THAT THE CODE OF CONDUCT PROPOSED BY PECO IS ADEQUATE TO PROTECT RATEPAYERS FROM ABUSES OF MARKET POWER?

A. While I believe that such a code of conduct is essential, I do not believe PECO's proposal is adequate. I am further concerned that its policing will require the expenditure of considerable Commission resources and thus distract the Commission from its many other obligations under the Competition Act.[16]

Q. ARE THERE OTHER OPTIONS AVAILABLE TO THE COMMISSION THAT CAN ADDRESS THESE CONCERNS ABOUT MARKET POWER ABUSE?

A. Yes, all of which have been adopted by other industries or by other states in their restructurings of their electric utility industry. Below, I identify and discuss a few of these options.

1. *Full divestiture of all generating and marketing affiliates of the LDU.*

This is the most effective option, since it eliminates any financial incentives for the LDU to abuse its market power as a monopoly with respect to the transmission and distribution of electricity to the advantage of its affiliates.[17] Since the LDU would have no affiliates, its

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[15] Staff Report on the Developments in the Wholesale Electric Power Market, Commonwealth of Virginia State Corporation Commission, Case No. PUE950089, May 1997, pp. 36-37.

[16] Apparently this concern is shared by Commissioner Quain. During a presentation Commissioner Quain made to the Joint Standing Committee on Utilities and Energy of the Maine State Legislature, he indicated that he expected to be innundated with complaints filed by competitors alleging anti-competitive behavior, discrimination and unfair trade practices on the part of the LDU in its relationships with its unregulated generation and marketing affiliates. (Augusta, Maine, April 4, 1997)

[17] Section 2804 (5) of the Act permits the Commission to authorize such a divestiture but not require one. This leaves open the possibility that the Commission could condition approval of certain benefits to PECO, e.g., securitization of stranded costs, on the full divestiture of generating assets and marketing affiliates.

incentive would be to maximize the amount of electricity flowing over its T&D network, irrespective of which electricity generation supplier or power marketer provided the electricity. This type of system is used with the airline industry, for example, where ownership and control over the air traffic control system is completely independent of any of the airlines that utilize the system, and has been adopted in part in the recently enacted Maine restructuring law. In addition, a number of utilities, including NEES, Southern California Edison and PG&E, have voluntarily undertaken to sell off generating assets to accommodate concerns regarding market power.

2. *LDU generating and marketing affiliates can be established only after the retail electricity market has been in operation for an amount of time necessary to ensure that competition exists within that market.*

This option permits the LDU to establish unregulated generating and marketing affiliates, but only after the Commission or another regulatory authority determines that the retail generating market within the LDU's service territory is competitive. The purpose of the delay is to provide an opportunity for competitors to establish themselves in the marketplace and for transactions to occur within the market that are between unaffiliated entities. These transactions will create benchmarks and working relationships that will make it more difficult for the LDU to subsequently favor its own affiliates. This type of system imposes constraints on the LDU monopoly that are similar to those imposed on the Bell Operating Companies with respect to the provision of inter-LATA long distance telephone service. In addition, Maine recently enacted a restructuring law that encourages competition in the retail electricity market by limiting the LDU to a total market share of 33%.

3. *LDU generating and marketing affiliates cannot provide services to customers within the service territory of the LDU.*

This option permits the LDU to establish unregulated generating and marketing affiliates, but limits the activities of those affiliates to providing services outside the service territory of the LDU. By imposing this limitation, the option reduces significantly the opportunity for the LDU to use its monopoly status within its service territory to provide a competitive advantage for its affiliates. This option was recently incorporated in the restructuring law enacted in New Hampshire, and has been used in the telecommunications industry to permit the Bell Operating Companies to offer inter-LATA services in regions outside of their local service territories.

Q. **PLEASE DESCRIBE YOUR THIRD CONCERN REGARDING THE MANNER IN WHICH PECO PROPOSES TO CARRY OUT ITS STATUTORY OBLIGATION TO SERVE AS A PROVIDER OF LAST RESORT.**

A. PECO proposes to retain its obligation to serve during the period in which it charges customers a CTC or an ITC and to do so at a total bundled rate that does not exceed the rate cap imposed by the Competition Act. The effect of this proposal is to ensure that PECO retains a substantial share of the total retail electricity market after retail access and to deny those customers who choose not to select an alternative electricity provider the full economic benefits of retail competition.

Q. **PLEASE EXPLAIN.**

A. Experience in the telecommunications industry suggests that there are many customers who, for a variety of reasons, will not exercise choice when permitted to as a consequence of restructuring and the introduction of competition into monopoly markets. Therefore, the only way in which these customers will receive the benefits of competition is if they face prices that are comparable to what exist in the market.

PECO's proposal will not do this. Instead, PECO has proposed to offer these customers fully bundled electric service at rates that effectively lock in the current relationship between PECO's current energy charge implicit in its bundled rates and what would otherwise exist in the market. In contrast, PECO will be charging those customers who select it as the supplier of choice a different price for energy – one based more closely on the prevailing market price for electricity[18]. To the extent that PECO's current implicit energy price is higher than what would be

[18] For example, PECO recently announced that it was selected, following a bid process, to provide full requirements service to the Kennebunk Light and Power municipal utility in Maine beginning in 1999. The prices contained in PECO's bid may bear little relationship to those it intends to charge its retail customers in its current service territory following restructuring.

charged by competitors[19], this differential will continue for as long as PECO retains the status as the provider of last resort.

Q. **HOW WOULD YOU PROPOSE THAT THE ECONOMIC BENEFITS OF COMPETITION BE EXTENDED TO CUSTOMERS WHO REMAIN WITH PECO UNDER ITS OBLIGATION TO SERVE?**

A. I believe that the simplest and most direct way to achieve this outcome is to require PECO to competitively bid the supply of electricity for this class of customers. By doing this, these customers will benefit from competition through the bid process and will pay market prices for the electricity they consume, despite the fact that they do not affirmatively elect to exercise choice in the competitive market. This type of system has been proposed for the provision of so-called "Standard Offer Service" in Massachusetts and will be implemented in Maine beginning in the year 2000 with the onset of retail access. The Maine law adds a further provision to promote competition by limiting incumbent utilities to a 20% market share of the Standard Offer service.

Q. **THE FOURTH CONCERN YOU RAISE RELATES TO PECO'S PROPOSAL TO RETAIN EXCLUSIVE RIGHT TO PROVIDE METERS AND METER READING SERVICES FOR ALL CUSTOMERS. PLEASE EXPLAIN WHY YOU BELIEVE THIS IS INCONSISTENT WITH THE ESTABLISHMENT OF A FULLY COMPETITIVE RETAIL ELECTRICITY MARKET.**

A. There are two reasons. First, there is nothing intrinsically monopolistic about the provision of metering equipment and the reading of those meters. Neither are there health and safety concerns which might otherwise require that the provision of these services be subject to Commission regulation. Thus, if it is true (and I believe it is) as the General Assembly found that "competitive market forces are more effective than economic regulation in controlling the cost of generating electricity", then I believe a very good case could be made – and has been made in California, New Hampshire and Maine – that these same competitive market forces could more effectively control the costs of metering electricity.

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[19] There are a couple of reasons why this is likely to be the case. First, PECO's generation has not been subjected to competitive pressures in the retail market and thus may not be operating as efficiently as it will operate after restructuring occurs. Second, competitors may be satisfied with achieving lower rates of profitability in the initial years following restructuring in order to gain entry and market share in the region's electricity marketplace.

Second, the cost effectiveness of a number of existing energy services, including such things as real-time pricing, load shifting, building automation systems and energy conservation measures, depends on their ability to interface with metering equipment. In fact, in many instances energy service companies today install parallel metering systems in conjunction with utility supplied meters to ensure compatability between metering and the electricity-related technologies and equipment installed and to maximize potential cost savings to the customer. These parallel metering systems represent an additional cost that energy service companies must pay that energy service affiliates of PECO may not face following restructuring, since PECO will control the primary metering equipment at the customer's premise. This cost disadvantage disappears when the choice of metering services is left to the discretion of the customer. The customer is then able to select a primary metering system that is offered, for example, by his or her full-service electricity generation supplier or marketer that is compatible with the energy services related technology and equipment supplied by the same company. The customer is not forced to pay for two metering systems, and thus the competitive supplier does not face a competitive disadvantage in this market.

Q. HOW WOULD YOU PROPOSE TO CORRECT THIS SITUATION?

A. I believe that metering equipment, meter reading and all related services and activities currently provided exclusively by PECO should be unbundled from transmission and distribution rates, and the customer should be given the option of selecting a provider(s). As noted above, other states are following this course of action to bring competition to an area that has been the exclusive domain of the incumbent monopoly utility and to reduce the competitive advantage that the incumbent utility has vis a vis competing energy service companies or full-service electricity generation suppliers or marketers.

Q. YOUR FINAL CONCERN IS THAT THE RECOVERY OF STRANDED COSTS THROUGH SECURITIZATION AND "INTANGIBLE TRANSITION CHARGES" GIVE PECO AN ADVANTAGE OVER POTENTIAL COMPETITORS BY PERMITTING IT TO ENTER THE COMPETITIVE MARKET WITH A SIGNIFICANTLY REDUCED DEBT POSITION AND WITH CASH IN HAND. PLEASE EXPLAIN.

A. One of the more attractive features of securitization to a utility with substantial stranded costs is that it reduces the utility's debt and provides a significant source of cash. The utility may elect to use this cash to buy back debt and/or equity. Alternatively, it may decide to use all or a portion of thecash to finacne new business ventures, including underwriting the securing of significant market share in the competitive retail electricity market. This latter option will have the effect of diluting equity in the short-term, but is designed to improve equity returns ove the longer-term. These options will not be available tocompetitors who, because of their foresight or just "dumb luck", are now low-cost producers of electricity with little or no stranded costs.[20]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[20] Of course, as Mr. Bradford and I argued in our testimony in Docket No. R-00973877, securitization raises a host of equity considerations. For example, securitization can be a very powerful stimulant for dormant stock prices as the equity buy-back effort of the utility can create significant upward pressure in the market. The consequences of this will accrue to stockholders and may far exceed any rate reduction benefits to ratepayers.

Exhibit SILKMAN-1

Regional Economic Models, Inc.

George I. Treyz, President

MODEL DOCUMENTATION FOR

THE REMI EDFS-53

FORECASTING AND SIMULATION

MODEL

JULY, 1996

REMI REFERENCE SET
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CHAPTER I

OVERVIEW OF THE REMI EDFS-53 MODEL

Regional Economic Models, Inc. (REMI) was established in 1980 to respond to the demand for regional forecasting and simulation models. The REMI methodology was first initiated in the mid-1970's as the TFS methodology, named after its original authors, Treyz, Friedlander, and Stevens. The Massachusetts Economic Policy Analysis model, developed in 1977, was the first implementation of this methodology. A core version of the model was then developed for the National Academy of Sciences. Now available for any county/state or combination of counties/states in the U.S., the standard REMI model is the Economic and Demographic Forecasting and Simulation 53-sector (EDFS-53) model.

Policy makers and analysts can use the EDFS-53 model to forecast and simulate policy changes in the regional economy. The baseline forecast (also called a control forecast) does not include any policy variable changes. A forecast that does include one or more policy variable changes is called an alternative forecast or a simulation. The difference between the control and alternative forecasts shows the effects of the policy change. Examples of such policy changes include decisions relating to tourism, the environment, transportation, energy, taxation, utility rates, and a wide variety of regional development projects.

Interindustry relationships are included in the REMI model, as well as behavioral equations from economic theory. This creates a model that will respond in a logical way to changes in an area's economy. The coupling of proven economic theory with customized data ensures state-of-the-art accuracy of your REMI EDFS-53 forecast and simulation. The result of the REMI modeling technique is a representation of a regional economy that predicts demand and supply conditions across 53 sectors, 94 occupations, 25 final-demand sectors, and 202 age/sex cohorts.

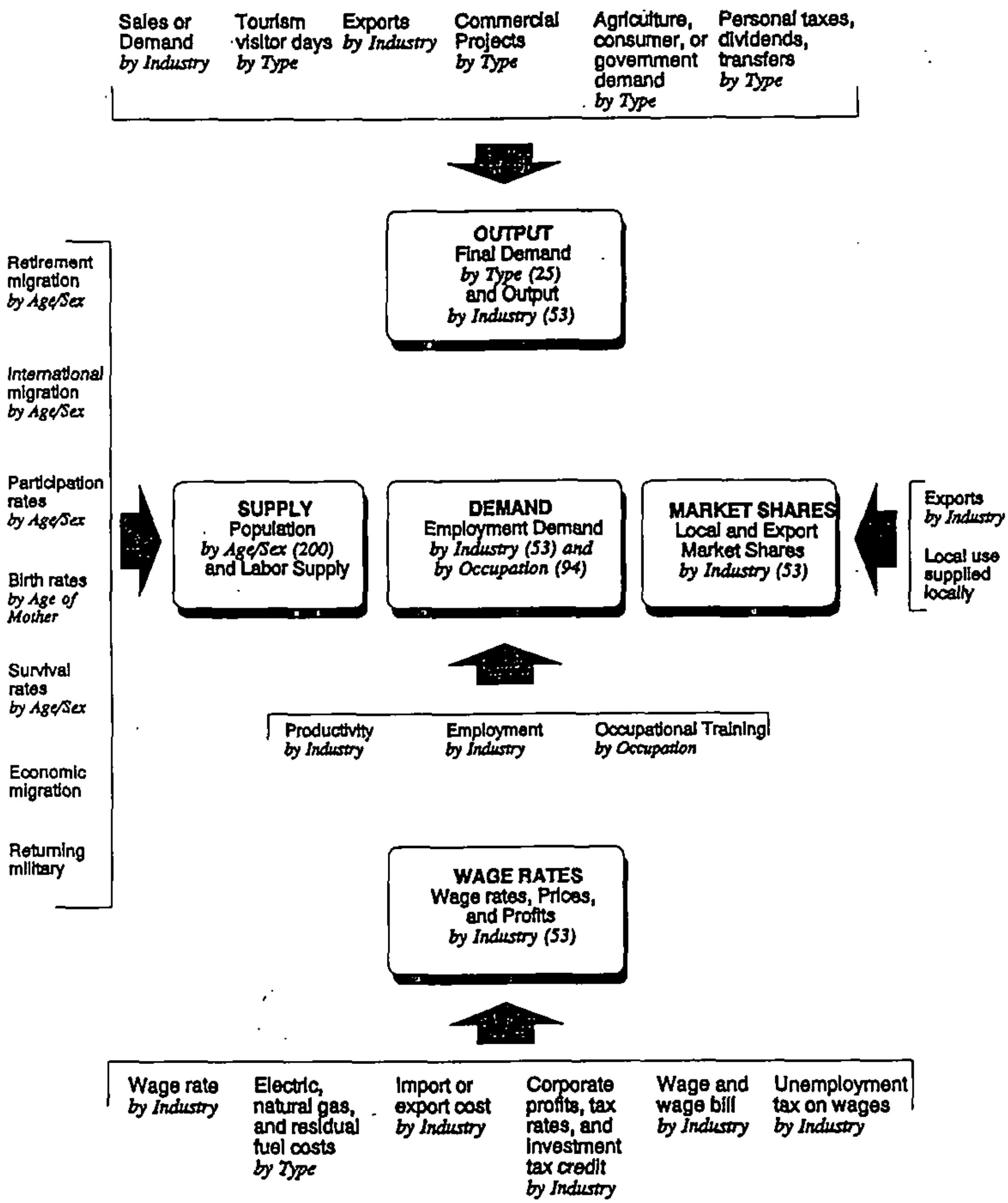
In contrast to traditional regional econometric models, REMI models are estimated using data from all regions and then calibrated to the specific region. This method allows us to estimate model parameters using a large data set that produces more econometrically reliable results than would be possible using data from only a single area. The model embodies a consistent internal structure that is widely documented in academic publications. We feel our users benefit from our on-going model research and development program at REMI.

A. SIMULATING THE EFFECTS OF POLICY CHANGE

A large variety of policy variables are available to the user for introducing the direct effects of a policy initiative into a REMI model. These are shown, together with the major components of the model which are directly influenced, in Figure 1. Along with a general discussion of policy variables, the effect of changing two policy variables (commercial and industrial electrical rates), will be described briefly in this section.

The effect of a policy change is the difference between a control forecast and an alternative forecast. The model is first used to generate a control forecast for as many years into the future, up to the year 2035, as the user wishes to evaluate. Next, the model is run to generate an alternative forecast, based in this case on the changed values for the relative electric fuel cost policy variables. In the REMI EDFS-53 model, there are over 1,000 regular economic policy variables and hundreds of translator policy variables (each of which uses a combination of regular economic policy variables) and demographic policy variables (which can be used to change over 1,300 variables for age/sex cohorts). Because of the large number of policy variables provided in the REMI model, the types of simulations that the user may run are considerable. For instance, the user may change regular economic policy variables for the policy simulation, such as tax rates (including rates for the corporate profit tax, equipment tax, investment tax, personal income tax, and property tax), costs (including relative production cost, import cost, and export cost), wage rate (or wage bill), employment, occupational demand, population, transfer payments and

Figure 1 Some of the Policy Variables and the Parts of the Model They Directly Influence



unemployment compensation, and final demand. A complete list of policy variables is presented in Chapter 11.

Each policy variable has a default value based on whether it is additive or multiplicative. In our simulation example, because the two policy variables for electric rates are multiplicative, their default values are 1.0. For a 10 percent increase, we changed their values to 1.10 by entering 10.0 when prompted by the simulation procedure.

Currently, the user can examine the forecast results of the REMI EDFS model for over 2,000 economic variables and several hundred demographic variables. The values for these variables are contained in 49 economic and 11 demographic tables which are output for the EDFS model. The user may choose to print one or several of the tables for the control forecast, the simulation, or the difference between the two. The user can also select the values of one or more variables and use them for other purposes, such as importing into LOTUS® for graphing.

Table 1-1 below shows the difference between the simulation and control forecasts from a sample session for selected variables and forecast years. Each element in the table represents an aggregated value from a detailed table for 49 private industries. In the sample shown, the effect of the 10% increase in rates can be seen in the fuel costs line where the average increase in fuel cost is shown to be 6.9 percent. This increase raised selling prices for the regional industries[1] which pass on their price increases to local markets by an average of .1 percent in 1991. For national industries that cannot pass on their cost increases, the 10% increase in rates decreased relative profits by .095 percent in the first forecast year and by .118 percent by 2035. The increased cost and reduced profits decreased exports by $24.77 million 1987 dollars in 1991, and by $279.39 million in 2035. However, some offset in the employment decline that this might have caused came through, resulting in an increase in labor intensity by .142 percent in the year 2035 as labor was substituted for fuel. Not shown on this table is a decrease

[1] For the definition of regional and national industries, see Chapters 2 and 3.

TABLE 1-1

MASSACHUSETTS: EFFECT OF 10% INCREASE IN ELECTRIC COST FOR INDUSTRIAL & COMMERCIAL USERS

TABLE 2: SUMMARY TABLE FOR PRIVATE NONFARM SECTORS.

(DETAILED TABLE # REF IN PARENS-(10 SECT,49 SECT))

	1991 FCST	1992 FCST	1993 FCST	1994 FCST	1995 FCST	2000 FCST	2005 FCST	2010 FCST	2020 FCST	2035 FCST
PRIVATE NONFARM EMPLOYMENT (IN THOUSANDS OF PEOPLE) AND ITS DECOMPOSTION BY SOURCE OF DEMAND:										
TOTAL EMPLYMNT (7,18)	-3.294	-3.803	-4.198	-4.482	-4.622	-4.757	-4.752	-4.509	-3.990	-3.916
INTERMEDIATE (7,19)	-.802	-1.040	-1.220	-1.352	-1.440	-1.691	-1.880	-1.939	-1.935	-1.872
LOCAL CONSUM (7,20)	-1.836	-2.006	-2.127	-2.240	-2.291	-2.327	-2.285	-2.127	-1.820	-2.041
GOVT DEMAND (7,21)	-.017	-.036	-.049	-.062	-.072	-.106	-.124	-.118	-.091	-.105
INVEST ACTVTY(8,22)	-.526	-.525	-.552	-.550	-.532	-.401	-.318	-.261	-.227	-.289
EXPORT TO US (8,23)	-.113	-.196	-.250	-.279	-.287	-.232	-.146	-.064	.083	.391
EXP - MULTREG(8,24)	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
EXOGENOUS (8,25)	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
COSTS AND SELLING PRICES RELATIVE TO THE U.S.:										
SELLING PRICE (9,26)	.00102	.00106	.00102	.00101	.00100	.00109	.00120	.00129	.00136	.00125
FACTOR INPUTS (9,27)	.00171	.00179	.00176	.00175	.00176	.00193	.00208	.00220	.00228	.00213
LABOR (9,28)	-.00026	-.00009	-.00012	-.00012	-.00010	.00016	.00039	.00057	.00065	.00043
FUEL (9,29)	.06938	.06938	.06938	.06938	.06938	.06938	.06938	.06938	.06938	.06938
CAPITAL (10,30)	.00030	.00029	.00026	.00023	.00022	.00022	.00025	.00029	.00035	.00029
INTRMED INPUTS(10,31)	.00055	.00056	.00053	.00050	.00049	.00054	.00062	.00069	.00076	.00067
OTHER VARIABLES:										
REL FACT PROD (10,32)	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
REL PROF MFG (10,33)	-.00095	-.00099	-.00098	-.00098	-.00098	-.00108	-.00116	-.00122	-.00125	-.00118
LABOR INTENSTY(11,34)	.00011	.00021	.00030	.00039	.00047	.00079	.00100	.00114	.00129	.00142
MULT ADJ (11,35)	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
EMP % OF U.S. (11,36)	-.003	-.003	-.004	-.004	-.004	-.004	-.003	-.003	-.003	-.003
RPC=SS/DEMAND (11,37)	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
AVG WAGE-THOUS(12,38)	-.003	.000	-.001	-.002	-.001	.006	.016	.030	.059	.090
INDL MIX INDX (12,39)	-.00011	-.00010	-.00008	-.00006	-.00005	.00002	.00005	.00005	.00003	.00005
IN BILLIONS OF 1987 $'S:										
DEMAND (12,40)	-.29758	-.35085	-.40010	-.43153	-.45602	-.53159	-.59332	-.62231	-.66428	-.83521
IMPORTS (12,41)	-.09333	-.10398	-.11451	-.11992	-.12357	-.12880	-.12986	-.12512	-.11709	-.16670
SELF SUPPLY (13,42)	-.20427	-.24688	-.28558	-.31158	-.33250	-.40279	-.46346	-.49722	-.54721	-.66847
EXPORTS (13,43)	-.02477	-.04609	-.06628	-.08145	-.09487	-.14687	-.19031	-.22095	-.25836	-.27939
INTRA-REG TRD (13,44)	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
EXOGENOUS PRDN(13,45)	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
OUTPUT (14,46)	-.22905	-.29295	-.35185	-.39304	-.42737	-.54965	-.65375	-.71817	-.80557	-.94791
GRP(VAL ADDED)(14,47)	-.12992	-.16372	-.19454	-.21626	-.23430	-.29895	-.35510	-.38943	-.43710	-.51938
IN BILLIONS OF NOMINAL $'S:										
WAGE&SAL DISB (14,48)	-.08422	-.08952	-.10479	-.11964	-.12975	-.15363	-.17172	-.18262	-.24829	-.77881

in population of 1,593 people in 1991 and 10,078 people in 2035. This decrease is caused by the employment effects of the policy and its effects on the real wage rate.

The above analysis gives an overview of the effects of a policy change. By examining detailed tables, the effects on individual occupations and industries can be determined.

B. MAJOR COMPONENTS AND LINKAGES

The REMI model can be separated into five key linkages. Each linkage contains a number of equations and performs a certain function in the model. These key linkages are: (1) *output* linkage; (2) labor and capital *demand* linkage; (3) population and labor *supply* linkage; (4) *wage,* price and profit linkage; and (5) market *share* linkage. The interaction among these five linkages is shown in Figure 2. Directly and indirectly, they are all interrelated with each other. In the model, a forecast result is obtained to satisfy all the equations simultaneously.

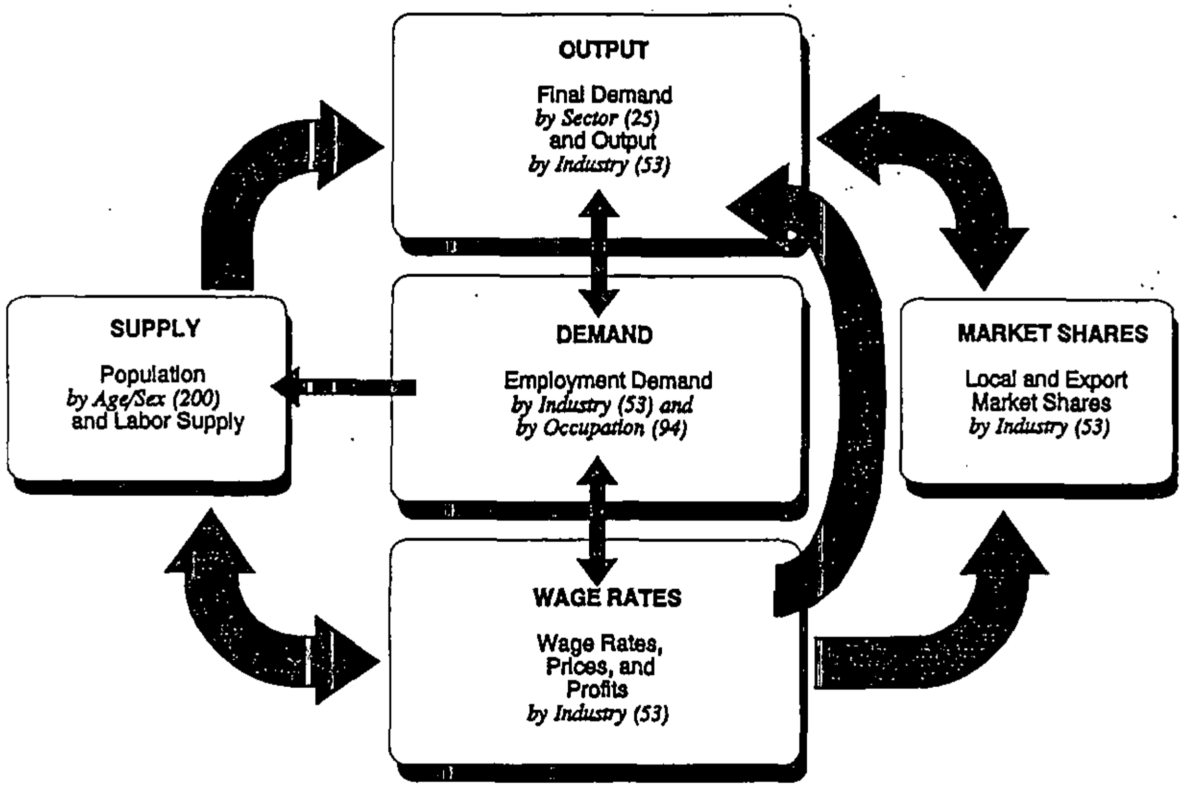
The *output* linkage in the model determines local demand for components of personal consumption which depends on real income, for investment demand which depends on relative factor prices and anticipated economic activity, and for government demand which is influenced by the size of the local population. These demands are translated into industry demand which also depends on the interstate and international exports, as well as on intra-regional exports in the context of a multi-area model.

Employment *demand* is, of course, affected by local output. However, it is also determined by the number of employees per dollar of output. This in turn depends, in part, on the relative costs of all of the factors of production.

The *supply* of labor depends on the population and its age/sex distribution. Population in turn depends on economic migration which is determined by expected income. This earnings expectation is determined by the probability of employment (the employment/labor force ratio), the real wage rate and, in part, by the mix of industries. In the EDFS model, the other types of migration (retirement, military, and international) are treated explicitly, as are the cohort survival aspects of population change.

Wage rates in the model depend on both demand and supply conditions. The overall supply and demand is reflected in the employment to labor force ratio, while occupation-specific demand/supply conditions depend on the rate of growth for occupation-specific employment.

Figure 2 Linkages Among the Major Parts of Your REMI Model



Finally, the local and export *shares* depend on local profitability and local selling prices. Both will be influenced by costs for all inputs to production, including labor costs.

C. ECONOMIC FOUNDATION OF THE REMI MODEL

The structure of the REMI model is based on economic assumptions that are shared by most economic professions. We assume that businesses are motivated by profit and individuals are motivated by a desire to maximize their well-being. We assume that firms buy inputs from other firms, and these linkages change in predictable ways over time. We also assume that firms can change the relative inputs into production based on relative cost changes. While we assert that individuals and firms in various parts of the country have similar motivations, we realize that each area of the country has differences that influence its economy uniquely and, therefore, that these differences must be estimated individually for each industry in each area.

D. USES OF THE REMI MODEL

For almost a decade, the REMI model has been widely used in the analysis of a variety of regional economic issues. Current clients for the model are located in over 20 states. They include state governments, planning agencies, universities, utility companies, and private consulting firms. Some of the recent applications of the REMI model are:

- Evaluation of the effects of a new auto plant, conducted separately for Michigan, Kentucky, Wisconsin, and Illinois;
- Analysis of a military facility expansion: Fort Drum in northern New York State;
- Separate studies of the effects of increases in utility costs for Georgia, Kansas City, and Central Illinois;
- Study of the best allocation of federal business start-up loans for Lehigh-Northampton counties in Pennsylvania;
- Effect of water rate changes for Denver and other cities in Colorado;
- Analysis of a new port development in Maine;
- Occupational forecasts conducted for the Boston region;
- Impact of a decline in the Georgia textile industry;
- Effect of an increase in higher education spending in Connecticut;
- Effect of changes in Minnesota's welfare policy;
- Industrial growth forecasts for Maine;
- Economic and demographic forecasts for El Paso, Texas;
- Multi-regional effect of federal military procurement for all the states in the U.S.;
- Effect of tax changes in separate studies for Colorado and Wisconsin;
- Impact of increased tourism on Kentucky;
- Effect of increased coal use in Illinois;
- Forecast of occupational and industrial wage rates for Massachusetts and New England;
- Impact of a horse racing track in Minnesota;
- Impact of the construction of a minor league baseball stadium in Buffalo, New York;

- Effect of heat and electricity cogeneration in Illinois;
- Long-term planning forecasting for Maine;
- Effect of new offshore drilling for three counties in California;
- Impact of a new shopping and entertainment complex in Minnesota;
- Analysis of increased labor productivity from education expenditures in Arkansas;
- Effect of urban transportation systems in San Francisco, Washington, D.C., Atlanta, and Boston;
- Analysis of alternative transportation investments for the entire U.S.;
- Impact of environmental air quality regulation on Illinois;
- Effect of a new paper mill in Wisconsin;
- Effect of an increase in the state minimum wage in Maine;
- Analysis of the economic effects of constructing nuclear waste dumps in the states of Nevada and Washington;
- Evaluation of the economic effects of options for improving a major road in Wisconsin;
- Identification and analysis of trends in Michigan's export base;
- Impact of reduced activity at a Nevada nuclear test site;
- Linkage to the ENERGY 2020 model for evaluation of energy price changes, conservation, and construction programs for state energy offices, regulators, and utilities;
- Impact of changing energy prices in Maine;
- Impact estimation of enforcement of chemical pollution control laws on sub-state areas of Illinois;
- Evaluation of the effects of proposed solid waste management rules on Minnesota; and
- Impact of pollution control regulations in the Los Angeles Basin.

E. ORGANIZATION OF THE MANUAL

The REMI model should be considered a flexible tool for policy analysis. This manual, intended primarily for the economic analyst, contains a technical description of the model that will help in developing and understanding the economic simulations which can be made using the EDFS-53 model.

The organization of this volume proceeds from a general introduction and description of the model, on through to the details of model construction and of parameters of the model. The numerous tables that are included are for use in examining the data, structure, and performance of the model.

In Chapters 2 and 3, we explain the equations used in the REMI model. Chapter 2 presents a single-industry, single-area, single-occupation, single-age/sex cohort, 2-factors of production, and 4-components of demand simple version of the model. The equations in Chapter 2 capture the most important ideas and links in the structure of the REMI model. In order to become familiar with the whole system, reading Chapter 2 should be the first step for the user.

A generalization of the simple-version model with n-industries, m-areas, p-occupations, v-age/sex cohorts, x-factors of production, and z-components of demand is introduced in Chapter 3. This chapter provides a detailed explanation of the model. It presents supplementary information that the simple version of the model in Chapter 2 does not provide. Reading Chapter 3 requires a more advanced mathematical and economic background.

In Chapter 4, the data sources and the model construction procedures are presented. Particular emphasis is given to the way that county employment data is drawn from the BLS 202 Establishment Employment data series, as well as from County Business Patterns (CBP) and the Bureau of Economic Analysis (BEA). Sources for other data used in the model are also covered.

In Chapter 5, we show how regional purchase coefficients, i.e. the proportion of local use supplied locally, are estimated at a very detailed level and then built up for the aggregate sector that is used for the EDFS-53 model.

In Chapter 6, we provide a list of the detailed industries and occupations used in the model. This list shows the industries and occupations for which the detailed coefficient matrices (in Chapters 7 and 8) correspond.

In Chapter 7, the last history year's technological matrix of the input-output model is shown. In the REMI model, the matrix is updated each year to reflect changing technology in the economy. In Chapter 8, the occupational proportion matrix is also shown for the last history year. Here again, the actual model uses an updated matrix for each year as staffing patterns are predicted to change.

In Chapter 9, we present history and control forecast tables. For multi-region models, these are shown for the total area as well as for the sub-areas included in the total model.

In Chapter 10, we present an introduction to simulations, again referring back to the model presented in Chapter 2, where the number of industries, occupations, etc. have been simplified. In Chapter 11, a fully-annotated policy variable list for the REMI EDFS model is presented. This list is extremely important in terms of using the model for simulations. By reading this chapter, you will be able to see what policy variables are available to you for carrying out policy simulations.

In Chapter 12, we present the detailed tables for the demographic model. In Chapter 13, the detailed I-O tables that are necessary for building the I-O model, along with an explanation of how our conjoined procedure operates, are presented.

This volume is the first of a three-volume set and is primarily focused both on the way the model is used and on its structure. The second volume in the series is the Operator's Manual. The Operator's Manual is much more focused on how one actually installs the model on a computer and then uses the model to carry out various procedures. Topics such as how to adjust your control forecast or how to do complicated policy simulations are included in the second volume. We have also included information about the U.S. model and the U.S. forecast in the Operator's Manual. The third volume of this three-volume set is the REMI Reprints volume. In the Reprints volume, we present not only reprints of articles about the model, but also published and unpublished information about both uses of the model and users of the model. This final volume should be used as a general reference volume and supplement to the other two.

Exhibit SILKMAN-2

REMI MODEL SIMULATION
BASE CASE

	FORECAST OR STUDY PERIOD											
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing	255.115	252.455	249.899	247.983	246.212	244.292	242.165	239.884	237.482	236.292	235.243	233.218
Durables	120.733	118.943	116.931	115.006	113.230	111.330	109.333	107.257	105.006	104.090	103.590	102.372
Nondurables	134.382	133.512	132.968	132.977	132.982	132.962	132.832	132.627	132.476	132.202	131.653	130.846
Non-manufacturing	1645.224	1671.473	1695.517	1718.994	1741.862	1765.913	1788.963	1810.764	1832.159	1758.295	1869.176	1886.650
Mining	1.953	1.921	1.914	1.906	1.898	1.885	1.869	1.849	1.826	1.808	1.782	1.754
Construction	94.885	95.395	96.138	97.001	97.839	98.747	99.587	100.281	100.954	101.538	102.391	103.136
Trans. + Pub. Utilities	93.398	93.726	94.032	94.406	94.720	95.001	95.201	95.304	95.394	95.120	94.417	93.556
Fin., Ins, Real Estate	202.505	203.458	204.374	205.357	206.163	206.919	207.425	207.744	207.890	207.373	207.650	207.666
Retail Trade	324.719	328.561	329.359	328.843	328.189	327.789	327.289	326.456	325.340	232.949	324.047	323.831
Wholesale Trade	102.893	102.928	102.613	102.197	101.739	101.310	100.807	100.210	99.633	99.223	99.144	98.846
Services	807.717	827.996	849.294	871.164	892.867	915.481	937.683	959.492	981.380	1000.248	1019.368	1037.165
Agri./Forestry/Fising	17.154	17.488	17.793	18.120	18.447	18.781	19.102	19.428	19.742	20.036	20.377	20.696
Government	239.074	235.960	237.078	238.229	239.446	240.702	241.977	243.294	244.587	245.092	246.488	247.907
State and Local	160.332	159.808	161.701	163.591	165.553	167.538	169.514	171.540	173.506	173.763	174.770	175.845
Federal - Civilian	60.337	58.639	57.963	57.324	56.686	56.067	55.477	54.886	54.331	54.374	54.621	54.849
Federal - Military	18.405	17.513	17.414	17.314	17.207	17.097	16.986	16.868	16.750	16.955	17.097	17.213
Farm	7.671	7.508	7.335	7.168	6.996	6.825	6.657	6.485	6.319	6.255	6.193	6.131
Total Employment	2147.084	2167.396	2189.829	2212.374	2234.516	2257.732	2279.762	2300.427	2320.547	2245.934	2357.100	2373.906
Disposable Personal Income	97.003	101.232	105.295	109.457	113.744	118.243	122.876	127.620	132.465	137.341	142.547	147.871
Price Index (1992=100)	117.405	120.092	122.830	125.625	128.464	131.370	134.332	137.343	140.418	143.580	146.847	150.202
Investment												
Residential	4.124	4.282	4.374	4.476	4.571	4.674	4.776	4.863	4.951	5.021	5.131	5.238
Non-Residential	3.197	3.355	3.496	3.648	3.803	3.962	4.119	4.273	4.426	4.587	4.768	4.939
Prod. Durable Equip.	9.873	10.771	11.361	11.993	12.645	13.325	13.760	14.683	15.363	16.128	16.964	17.770
Total Fixed Investment	17.194	18.409	19.230	20.118	21.018	21.961	22.654	23.819	24.740	25.737	26.863	27.947

Notes:

Employment Figures in thousands of people employed

Disposable Personal Income and Investment in billions of nominal dollars

Exhibit SILKMAN-3

REMI MODEL SIMULATION
PECO RESTRUCTURING PROPOSAL

FORECAST OR STUDY PERIOD

All Figures are changes relative to the Base Case presented in Exhibit SILKMAN-2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing		0.057	0.082	0.098	0.110	0.120	0.127	0.133	0.137	0.140	0.144	0.145
Durables		0.020	0.028	0.033	0.036	0.039	0.041	0.043	0.044	0.045	0.047	0.048
Nondurables		0.037	0.054	0.065	0.074	0.081	0.086	0.090	0.093	0.095	0.097	0.097
Non-manufacturing		1.135	1.310	1.325	1.327	1.325	1.322	1.322	1.320	1.318	1.318	1.319
Mining		0.000	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Construction		0.013	0.127	0.122	0.116	0.111	0.106	0.102	0.098	0.095	0.092	0.090
Trans + Pub Util		0.040	0.044	0.046	0.047	0.049	0.050	0.051	0.053	0.054	0.055	0.055
Fin., Ins, Real Estate		0.105	0.112	0.113	0.113	0.112	0.111	0.110	0.109	0.107	0.106	0.106
Retail Trade		0.402	0.407	0.402	0.393	0.384	0.374	0.365	0.356	0.347	0.340	0.333
Wholesale Trade		0.059	0.065	0.068	0.070	0.071	0.072	0.073	0.073	0.074	0.075	0.076
Services		0.507	0.544	0.563	0.577	0.588	0.599	0.610	0.620	0.630	0.639	0.648
Agri./Forestry/Fising		0.009	0.010	0.010	0.010	0.010	0.010	0.011	0.011	0.011	0.011	0.011
Government		0.025	0.056	0.078	0.097	0.114	0.129	0.142	0.154	0.162	0.170	0.177
State and Local		0.025	0.056	0.078	0.097	0.114	0.129	0.142	0.154	0.162	0.170	0.177
Federal - Civilian		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Federal - Military		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Farm		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Employment		1.217	1.448	1.501	1.534	1.559	1.578	1.597	1.611	1.620	1.632	1.641
Disposable Personal Income		0.076	0.083	0.089	0.095	0.099	0.104	0.108	0.111	0.115	0.118	0.122
Price Index (1992=100)	117.405	119.975	122.708	125.503	128.339	131.240	134.196	137.201	140.270	143.424	146.684	150.031
Investment												
Residential		0.017	0.016	0.015	0.014	0.013	0.012	0.012	0.011	0.010	0.010	0.011
Non-Residential		0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003
Prod. Durable Equip.		0.016	0.015	0.015	0.015	0.014	0.015	0.014	0.013	0.013	0.013	0.012
Total Fixed Investment		0.037	0.036	0.035	0.035	0.031	0.031	0.030	0.028	0.027	0.026	0.026
Tax Revenues												
State Government		0.009	0.010	0.011	0.012	0.012	0.013	0.013	0.014	0.014	0.014	0.015
Individual Income Tax		0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007
Sales Tax		0.005	0.005	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007	0.008

Notes:

Employment Figures in thousands of people employed

Income, Investment and Tax revenues in billions of dollars

State Tax Revenues computed based on ratio of disposable income to tax revenues for PA Fiscal Year 1994

State Sales Tax	6.34%
State Personal Income Tax	5.92%

PECO RATES vs. REGIONAL PEER GROUP

	Residential (500 kWh/Month)	Commercial (Avg. Cost per kWh)	Industrial (5MW, 2,500 MWh/Month)
LILCO	$0.1673	$0.1245	$0.1145
CON ED	$0.1621	$0.1168	$0.0961
Atlantic Electric	$0.1352	$0.1046	$0.0859
PSE&G	$0.1256	$0.0962	$0.0741
PP&L	$0.1211	$0.0771	$0.0684
Baltimore G&E	$0.1175	$0.0684	$0.0663
Duquesne	$0.1048	$0.0810	$0.0629
MET ED	$0.0966	$0.0800	$0.0554
Penn Power	$0.0951	$0.0800	$0.0545
Penn Electric	$0.0940	$0.0800	$0.0520
Delmarva	$0.0918	$0.0712	$0.0514
West Penn Power	$0.0715	$0.0581	$0.0382
Average	$0.1152	$0.0865	$0.0683
PECO	$0.1407	$0.1062	$0.0776
Required Rate Change	-18.11%	-18.56%	-11.97%

Sources: PECO response to Data Request OCA-IX-18(a), Pages 27 and 28 for residential and industrial classes
Energy User News Survey for commercial (except Baltimore G&E - 1996 10-K and MET ED, Penn Power and Pennsylvania Electric which are estimated at $.0800.

PECO RATES vs. NATIONAL AVERAGE

	Residential	Commercial	Industrial
U.S. National Average (1996)	$0.0839	$0.0763	$0.0460
PECO	$0.1407	$0.1062	$0.0776
Required Rate Change	-40.37%	-28.15%	-40.72%

Source: Dept. of Energy, "Retail Prices of Electricity Sold by Electric Utilities"

PECO RATES - PHASED REDUCTION TO NATIONAL AVERAGE

	Required Rate Changes		
	Residential	Commercial	Industrial
1998	-10.00%	-10.00%	-10.00%
1999	-13.04%	-11.82%	-13.07%
2000	-16.07%	-13.63%	-16.14%
2001	-19.11%	-15.45%	-19.22%
2002	-22.15%	-17.26%	-22.29%
2003	-25.18%	-19.08%	-25.36%
2004	-28.22%	-20.89%	-28.43%
2005	-31.26%	-22.71%	-31.51%
2006	-34.30%	-24.52%	-34.58%
2007	-37.33%	-26.34%	-37.65%
2008	-40.37%	-28.15%	-40.72%

REMI MODEL SIMULATION
10% ACROSS-THE-BOARD REDUCTION

FORECAST OR STUDY PERIOD

All Figures are changes relative to the Base Case presented in Exhibit SILKMAN-2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing		0.197	0.279	0.338	0.381	0.415	0.439	0.458	0.472	0.484	0.493	0.500
Durables		0.069	0.095	0.113	0.125	0.135	0.142	0.147	0.151	0.156	0.161	0.165
Nondurables		0.128	0.184	0.225	0.256	0.280	0.297	0.311	0.321	0.328	0.332	0.335
Non-manufacturing		4.257	4.452	4.513	4.525	4.526	4.520	4.512	4.505	4.496	4.501	4.502
Mining		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Construction		0.440	0.432	0.416	0.397	0.379	0.363	0.347	0.334	0.323	0.314	0.307
Trans + Pub Util		0.137	0.150	0.157	0.162	0.167	0.171	0.175	0.180	0.184	0.187	0.189
Fin., Ins, Real Estate		0.357	0.380	0.385	0.385	0.383	0.380	0.376	0.371	0.365	0.362	0.359
Retail Trade		1.366	1.383	1.367	1.338	1.307	1.275	1.243	1.211	1.181	1.158	1.134
Wholesale Trade		0.201	0.221	0.232	0.239	0.244	0.247	0.250	0.252	0.254	0.257	0.260
Services		1.724	1.852	1.921	1.968	2.009	2.047	2.083	2.118	2.150	2.183	2.212
Agri./Forestry/Fising		0.030	0.032	0.033	0.034	0.035	0.035	0.036	0.037	0.037	0.038	0.039
Government		0.084	0.189	0.263	0.330	0.388	0.439	0.484	0.523	0.552	0.579	0.601
State and Local		0.084	0.189	0.263	0.330	0.388	0.439	0.484	0.523	0.552	0.579	0.601
Federal - Civilian		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Federal - Military		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Farm		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Employment		4.538	4.920	5.114	5.236	5.329	5.398	5.454	5.500	5.532	5.573	5.603
Disposable Personal Income		0.257	0.280	0.302	0.320	0.336	0.350	0.364	0.377	0.389	0.401	0.412
Price Index (1992=100)	117.405	119.975	122.708	125.503	128.339	131.240	134.196	137.201	140.270	143.424	146.684	150.031
Investment												
Residential		0.058	0.054	0.051	0.047	0.045	0.043	0.040	0.038	0.036	0.034	0.033
Non-Residential		0.017	0.016	0.016	0.015	0.014	0.015	0.014	0.013	0.013	0.012	0.012
Prod. Durable Equip.		0.052	0.052	0.051	0.051	0.050	0.048	0.047	0.045	0.044	0.043	0.042
Total Fixed Investment		0.126	0.121	0.119	0.114	0.109	0.106	0.100	0.095	0.093	0.088	0.087
Tax Revenues												
State Government		0.032	0.034	0.037	0.039	0.041	0.043	0.045	0.046	0.048	0.049	0.051
Individual Income Tax		0.015	0.017	0.018	0.019	0.020	0.021	0.022	0.022	0.023	0.024	0.024
Sales Tax		0.016	0.018	0.019	0.020	0.021	0.022	0.023	0.024	0.025	0.025	0.026

Notes:

Employment Figures in thousands of people employed

Income, Investment and Tax revenues in billions of dollars

State Tax Revenues computed based on ratio of disposable income to tax revenues for PA Fiscal Year 1994

State Sales Tax	6.34%
State Personal Income Tax	5.92%

REMI MODEL SIMULATION
REDUCTION TO REGIONAL PEER GROUP AVERAGE

FORECAST OR STUDY PERIOD
All Figures are changes relative to the Base Case presented in Exhibit SILKMAN-2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing		0.302	0.412	0.490	0.549	0.597	0.637	0.670	0.697	0.723	0.746	0.763
Durables		0.107	0.143	0.167	0.185	0.200	0.213	0.224	0.234	0.246	0.258	0.267
Nondurables		0.195	0.269	0.323	0.364	0.397	0.424	0.446	0.463	0.477	0.488	0.496
Non-manufacturing		7.810	8.090	8.140	8.112	8.074	8.036	8.267	7.959	7.934	7.933	7.927
Mining		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Construction		0.805	0.781	0.745	0.707	0.672	0.640	0.612	0.588	0.568	0.553	0.540
Trans + Pub Util		0.249	0.267	0.277	0.283	0.290	0.297	0.304	0.312	0.318	0.324	0.329
Fin., Ins, Real Estate		0.656	0.693	0.698	0.694	0.689	0.681	0.975	0.662	0.652	0.646	0.640
Retail Trade		2.516	2.532	2.490	2.427	2.362	2.299	2.235	2.173	2.117	2.072	2.027
Wholesale Trade		0.360	0.388	0.401	0.408	0.413	0.416	0.418	0.420	0.424	0.429	0.434
Services		3.166	3.367	3.465	3.528	3.582	3.636	3.685	3.735	3.784	3.837	3.884
Agri./Forestry/Fising		0.055	0.059	0.061	0.062	0.063	0.064	0.035	0.066	0.068	0.069	0.070
Government		0.155	0.346	0.480	0.599	0.703	0.794	0.873	0.942	0.993	1.040	1.080
State and Local		0.155	0.346	0.480	0.599	0.703	0.794	0.873	0.942	0.993	1.040	1.080
Federal - Civilian		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Federal - Military		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Farm		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Employment		8.267	8.848	9.110	9.260	9.374	9.467	9.810	9.598	9.650	9.719	9.770
Disposable Personal Income		0.465	0.501	0.537	0.568	0.594	0.617	0.640	0.661	0.681	0.702	0.722
Price Index (1992=100)	117.405	119.868	122.595	125.388	128.221	131.117	134.068	137.067	140.130	143.278	146.530	149.871
Investment												
Residential		0.105	0.099	0.093	0.086	0.081	0.076	0.071	0.067	0.064	0.062	0.058
Non-Residential		0.029	0.027	0.028	0.026	0.025	0.024	0.022	0.021	0.020	0.019	0.019
Prod. Durable Equip.		0.093	0.089	0.089	0.087	0.084	0.080	0.077	0.074	0.072	0.070	0.069
Total Fixed Investment		0.228	0.216	0.209	0.199	0.190	0.181	0.170	0.163	0.156	0.151	0.147
Tax Revenues												
State Government		0.057	0.061	0.066	0.070	0.073	0.076	0.078	0.081	0.083	0.086	0.089
Individual Income Tax		0.028	0.030	0.032	0.034	0.035	0.037	0.038	0.039	0.040	0.042	0.043
Sales Tax		0.029	0.032	0.034	0.036	0.038	0.039	0.041	0.042	0.043	0.044	0.046

Notes:

Employment Figures in thousands of people employed

Income, Investment and Tax revenues in billions of dollars

State Tax Revenues computed based on ratio of disposable income to tax revenues for PA Fiscal Year 1994

State Sales Tax	6.34%
State Personal Income Tax	5.92%

REMI MODEL SIMULATION
REDUCTION TO NATIONAL AVERAGE

FORECAST OR STUDY PERIOD

All Figures are changes relative to the Base Case presented in Exhibit SILKMAN-2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing		0.837	1.206	1.477	1.671	1.813	1.916	1.989	2.036	2.071	2.093	2.098
Durables		0.288	0.403	0.482	0.535	0.572	0.598	0.616	0.626	0.640	0.653	0.659
Nondurables		0.549	0.803	0.995	1.136	1.241	1.318	1.373	1.410	1.431	1.440	1.439
Non-manufacturing		16.050	16.545	16.844	16.959	17.020	17.061	17.086	17.115	17.117	17.166	17.193
Mining		0.006	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006
Construction		1.667	1.618	1.563	1.498	1.434	1.374	1.319	1.270	1.227	1.193	1.162
Trans + Pub Util		0.526	0.564	0.594	0.616	0.636	0.655	0.672	0.690	0.703	0.714	0.722
Fin., Ins, Real Estate		1.356	1.411	1.434	1.437	1.434	1.426	1.414	1.401	1.383	1.374	1.365
Retail Trade		5.143	5.133	5.085	4.993	4.889	4.783	4.676	4.571	4.468	4.390	4.307
Wholesale Trade		0.778	0.847	0.899	0.932	0.957	0.975	0.989	1.000	1.010	1.023	1.033
Services		6.459	6.845	7.138	7.350	7.535	7.710	7.876	8.042	8.182	8.326	8.455
Agri./Forestry/Fising		0.115	0.120	0.124	0.126	0.128	0.131	0.133	0.135	0.138	0.140	0.143
Government		0.315	0.708	0.988	1.238	1.459	1.651	1.821	1.970	2.081	2.183	2.270
State and Local		0.315	0.708	0.988	1.238	1.459	1.651	1.821	1.970	2.081	2.183	2.270
Federal - Civilian		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Federal - Military		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Farm		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Employment		17.202	18.459	19.309	19.868	20.292	20.628	20.896	21.121	21.269	21.442	21.561
Disposable Personal Income		1.015	1.101	1.187	1.261	1.326	1.384	1.438	1.490	1.538	1.585	1.630
Price Index (1992=100)	117.405	119.738	122.453	125.245	128.076	130.966	133.909	136.899	139.952	143.088	146.330	149.659
Investment												
Residential		0.211	0.201	0.189	0.178	0.168	0.158	0.149	0.141	0.135	0.129	0.123
Non-Residential		0.061	0.060	0.061	0.060	0.059	0.056	0.055	0.052	0.050	0.048	0.046
Prod. Durable Equip.		0.199	0.195	0.200	0.200	0.196	0.191	0.186	0.181	0.175	0.171	0.168
Total Fixed Investment	0.000	0.471	0.456	0.451	0.438	0.423	0.406	0.390	0.374	0.359	0.348	0.337
Tax Revenues												
State Government		0.124	0.135	0.146	0.155	0.163	0.170	0.176	0.183	0.189	0.194	0.200
Individual Income Tax		0.060	0.065	0.070	0.075	0.079	0.082	0.085	0.088	0.091	0.094	0.097
Sales Tax		0.064	0.070	0.075	0.080	0.084	0.088	0.091	0.094	0.097	0.100	0.103

Notes:

Employment Figures in thousands of people employed

Income, Investment and Tax revenues in billions of dollars

State Tax Revenues computed based on ratio of disposable income to tax revenues for PA Fiscal Year 1994

State Sales Tax	6.34%
State Personal Income Tax	5.92%

REMI MODEL SIMULATION
PHASED REDUCTION TO NATIONAL AVERAGE

FORECAST OR STUDY PERIOD

All Figures are changes relative to the Base Case presented in Exhibit SILKMAN-2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Employment												
Manufacturing		0.197	0.334	0.474	0.616	0.763	0.913	1.067	1.221	1.382	1.547	1.712
Durables		0.069	0.114	0.158	0.201	0.245	0.289	0.333	0.376	0.424	0.476	0.526
Nondurables		0.128	0.220	0.316	0.415	0.518	0.624	0.734	0.845	0.958	1.071	1.186
Non-manufacturing		4.257	5.535	6.718	7.871	9.022	10.183	11.346	12.524	13.705	14.946	16.233
Mining		0.002	0.002	0.003	0.003	0.003	0.004	0.004	0.005	0.005	0.006	0.006
Construction		0.440	0.544	0.637	0.724	0.807	0.888	0.967	1.045	1.122	1.203	1.283
Trans + Pub Util		0.137	0.185	0.229	0.274	0.319	0.366	0.414	0.464	0.513	0.562	0.651
Fin., Ins. Real Estate		0.357	0.471	0.571	0.665	0.757	0.846	0.931	1.012	1.089	1.173	1.255
Retail Trade		1.366	1.728	2.051	2.354	2.644	2.925	3.193	3.453	3.708	3.974	4.232
Wholesale Trade		0.201	0.272	0.339	0.405	0.471	0.537	0.603	0.671	0.740	0.814	0.888
Services		1.724	2.293	2.838	3.387	3.952	4.539	5.145	5.775	6.418	7.093	7.785
Agri./Forestry/Fising		0.030	0.040	0.050	0.059	0.069	0.078	0.089	0.099	0.110	0.121	0.133
Government		0.084	0.211	0.334	0.468	0.612	0.763	0.922	1.088	1.247	1.416	1.587
State and Local		0.084	0.211	0.334	0.468	0.612	0.763	0.922	1.088	1.247	1.416	1.587
Federal - Civilian		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Federal - Military		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Farm		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Employment		4.538	6.080	7.526	8.955	10.397	11.859	13.335	14.833	16.334	17.909	19.532
Disposable Personal Income		0.257	0.353	0.456	0.563	0.674	0.790	0.911	1.039	1.171	1.311	1.456
Price Index (1992=100)	117.405	119.975	122.685	125.455	128.265	131.140	134.066	137.039	140.072	143.187	146.403	149.703
Investment												
Residential		0.058	0.069	0.080	0.091	0.101	0.111	0.121	0.132	0.142	0.151	0.162
Non-Residential		0.017	0.020	0.024	0.028	0.033	0.036	0.041	0.045	0.049	0.054	0.058
Prod. Durable Equip.		0.052	0.065	0.080	0.095	0.109	0.125	0.140	0.155	0.173	0.192	0.211
Total Fixed Investment		0.126	0.153	0.184	0.214	0.243	0.272	0.301	0.332	0.364	0.397	0.431
Tax Revenues												
State Government		0.032	0.043	0.056	0.069	0.083	0.097	0.112	0.127	0.144	0.161	0.178
Individual Income Tax		0.015	0.021	0.027	0.033	0.040	0.047	0.054	0.062	0.069	0.078	0.086
Sales Tax		0.016	0.022	0.029	0.036	0.043	0.050	0.058	0.066	0.074	0.083	0.092

Notes:

Employment Figures in thousands of people employed

Income, Investment and Tax revenues in billions of dollars

State Tax Revenues computed based on ratio of disposable income to tax revenues for PA Fiscal Year 1994

State Sales Tax	6.34%
State Personal Income Tax	5.92%

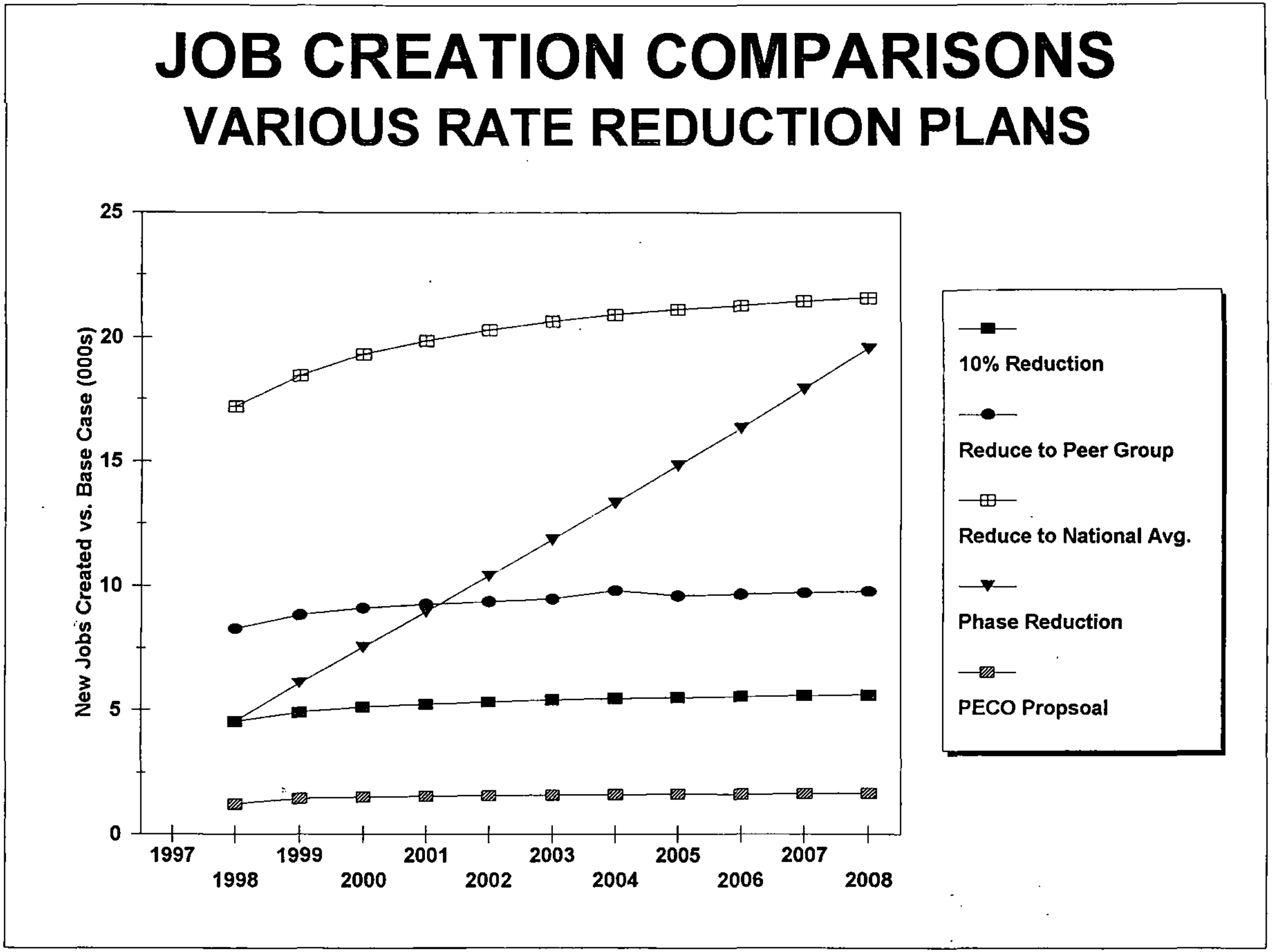


Exhibit SILKMAN-6