OTS Statement No. 1
Witness: Kevan L. Deardorff
Date: June 29, 2004

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DOCUMENT

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Direct Testimony**

**of**

**Kevan L. Deardorff**

**Office of Trial Staff**



**Concerning:**

**Rate of Return**

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

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

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

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff (OTS) as an expert witness.

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

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

## I. Subject of Testimony

**Q. PLEASE IDENTIFY THE ISSUES THAT ARE ADDRESSED IN YOUR TESTIMONY.**

A. The issues addressed in my direct testimony concern rate of return, including the cost of common equity, and the overall fair rate of return for the PPL Electric Corporation ("PPL" or "Company").

**Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT THAT SUPPORTS YOUR RECOMMENDATIONS WITH RESPECT TO A FAIR RATE OF RETURN?**

A. Yes. OTS Exhibit No. 1 presents the analyses that I have conducted regarding rate of return.

## II. Background Discussion

**Q. HOW DOES THE RATE OF RETURN COMPONENT FIT WITHIN THE REVENUE REQUIREMENT FORMULA?**

A. The revenue requirement formula is as follows:

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

Where:

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

In the above formula, the rate of return is expressed as a percentage. The calculation of that rate is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is

dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

**Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?**

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

The Bluefield Water Works and Hope Natural Gas cases of 1923 and 1944, respectively (cited below), set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

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

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

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

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

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

**Q. WOULD YOU PLEASE EXPLAIN HOW YOU CALCULATED YOUR OVERALL RATE OF RETURN?**

A. Yes. The overall rate of return in this rate proceeding is calculated using the weighted average cost of capital method, which is the interaction of the following components: the percentage of long-term debt; the percentage of common equity; the cost of long-term debt and the cost rate of common equity. First, it is necessary to determine the proportion of each type of capital (referred to as the capital structure) which has financed the rate base and assign the appropriate cost rate to each. The cost rate of debt is fixed and can be computed accurately. The cost rate of common equity is not fixed and is much more difficult to measure.

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

## III. Company Position

### A. Summary

**Q. WHAT IS THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE?**

A. Mr. Paul R. Moul, the Company's cost of capital witness, recommended the following rate of return for PPL:

| | Weighted Capital Structure (%) | Cost Rate (%) | Cost Rate (%) |
|---|---|---|---|
| Long-Term Debt | 51.30 | 6.43 | 3.30 |
| Preferred Stock | 1.83 | 6.19 | 0.11 |
| Common Equity | 46.87 | 11.50 | 5.39 |
| Total | 100.00 | | 8.80 |

Source: PPL Exhibit PRM-1, Page 1, Schedule 1.

B. Basis

**Q. WHAT IS THE BASIS FOR PPL'S CLAIMED CAPITAL STRUCTURE?**

A. At Page 19 of PPL Statement No. 9, Mr. Moul states that it is appropriate to use the capital structure of the Company for rate making purposes since the Company raises its own debt and preferred stock directly in the capital markets. The Company's estimated capital structure at December 31, 2004, consists of 51.30 percent long-term debt, 1.83 percent preferred stock, and 46.87 percent common equity. Mr. Moul also believes that this prospective capital structure reflects all know changes that will occur during the course of the future test year and considers conditions that will exist during the period of time the proposed rate will be effective.

**Q. WHAT IS THE BASIS FOR PPL'S COST OF DEBT CLAIM?**

A. The calculation of PPL's cost rate of long-term debt is shown on Mr. Moul's Schedule 7, Page 13. The long-term debt cost rate of 6.43 percent is a weighted cost rate based on PPL's debt issues expected to be outstanding at December 31, 2004. This estimated cost rate includes the maturity and early redemption of a total of 130.6 million of long term debt and the recognition of the call premiums on the early redemption of the high cost debt.

**Q. WHAT IS THE BASIS FOR PPL'S COST OF PREFERRED STOCK CLAIM?**

A. The calculation of PPL's cost rate of preferred stock is shown on Mr. Moul's Schedule 8, Page 16. The preferred stock cost rate of 6.19 percent is a weighted cost rate based on PPL's preferred stock issues expected to be outstanding at December 31, 2004.

**Q. WHAT IS THE BASIS FOR PPL'S COST OF EQUITY CLAIM?**

A. Mr. Moul summarizes his cost of equity analysis on Pages 3 through 5 of PPL Statement No. 9, wherein he recommends that an 11.50 percent common equity cost rate be used in this proceeding. To determine his cost of common equity, Mr. Moul states that he relied upon four well-recognized measures: the Discounted Cash Flow (DCF), the Risk Premium (RP), the Capital Asset Pricing Model (CAPM), and the Comparable Earnings (CE) approach. He applied the DCF and the CAPM methods to a group of nine electric companies referred to as the "Electric Group" and a group of eight natural gas companies referred to as the "Gas Group". The RP results were derived from common equity returns for the S&P Public Utility Index and long-term debt returns for the Public Utility Bond Index. The CE model was applied to a barometer group of thirty-eight unregulated companies. The results from these models ranged from 10.69% to 14.25%.

## III. OTS Position

### A. Summary

**Q. WILL YOU PLEASE SUMMARIZE YOUR RECOMMENDATION?**

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

| | Capital Structure (%) | Cost Rate (%) | Weighted Cost Rate (%) |
|---|---|---|---|
| Long-term Debt | 51.30 | 6.43 | 3.30 |
| Preferred Stock | 1.83 | 6.19 | 0.11 |
| Common Equity | 46.87 | ***8.75*** | ***4.10*** |
| Total | 100.00 | | ***7.51*** |

Source: OTS Exhibit No. 1, Schedule No. 1.

### B. Elements Adopted

**Q. HAVE YOU ADOPTED ANY ELEMENTS OF THE COMPANY'S RECOMMENDATION IN ARRIVING AT YOUR POSITION?**

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

### C. Elements Disputed

**Q. HOW DOES YOUR RECOMMENDATION DIFFER FROM THE COMPANY'S CLAIM?**

A. In the table on the preceding Page, I have italicized and bolded the numbers where my recommendation differs from the Company's rate of return claim. My recommendation differs in two areas: the cost rate of common equity, and the

overall rate of return. I recommend an 8.75 percent cost rate of common equity in lieu of Mr. Moul's 11.50 percent recommendation. As a result, my overall rate of return is 7.51 percent in lieu of the Company's 8.80 percent.

## IV. Cost of Common Equity

### A. Basis for Determining the Cost of Common Equity

**Q. WHAT IS THE BASIS FOR YOUR 8.75 PERCENT COST OF EQUITY RECOMMENDATION?**

A. I used the Discounted Cash Flow (DCF) method applied to two barometer groups of electric companies and PPL Corporation to determine my 8.75 percent cost rate of common equity. To compute the various components of the DCF method, I relied upon current, historical, and forecasted market data for PPL Corporation and each company in the two barometer groups.

**Q. WHAT FACTORS INFLUENCED YOU TO GIVE WEIGHT TO THE DCF RESULTS FOR PPL CORPORATION?**

A. PPL Corporation has adequate financial and market data to use in a DCF analysis. Also, PPL, being a wholly owned subsidiary of PPL Corporation, receives all of its common equity from the parent.

B. Barometer Groups

**Q. WHY HAVE YOU ALSO USED BAROMETER GROUPS IN YOUR DCF ANALYSIS?**

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

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

**Q. WHAT CRITERIA DID YOU USE TO SELECT YOUR PRIMARY BAROMETER GROUP?**

A. My primary barometer group consists of all electric companies in Mr. Moul's barometer group but excludes the companies that did not have at least two sources of analysts' forecasts of earnings growth.

**Q. WHAT COMPANIES ARE INCLUDED IN YOUR PRIMARY BAROMETER GROUP?**

A. The six companies in my primary barometer group are:

Consolidated Edison, Inc.

Duquesne Light Holdings, Inc.

Energy East Corporation

Northeast Utilities

NSTAR

Pepco Holdings, Inc.

My analysis also includes Mr. Moul's barometer group of nine electric companies.

### C. Economic Factors

**Q. DOES YOUR COST OF EQUITY ANALYSIS TAKE CHANGING BUSINESS AND ECONOMIC CONDITIONS INTO ACCOUNT?**

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

**Q. WHAT ECONOMIC FACTORS DO YOU CONSIDER IMPORTANT IN YOUR ANALYSIS OF COST OF CAPITAL?**

A. I have made comparisons of important economic variables and have examined their impact on electric utilities over the past twenty-three years. Schedule No. 3 of OTS Exhibit No. 1 presents a historical perspective of the Moody's "Aaa" Corporate Bond Yield, the U.S. Treasury Bill rate (T-Bill), the prime rate, and the percent change in the Consumer Price Index (CPI) compared to the average dividend yield of my barometer group for the same period. This schedule also presents a sampling of economic experts' quarterly forecasts for 2004 and 2005 and yearly forecasts for the period 2005 to 2014.

**Q. IS THERE A RELATIONSHIP BETWEEN DIVIDEND YIELDS OF ELECTRIC COMPANIES AND "Aaa" BOND YIELDS?**

A. Yes. A comparison of the "Aaa" bond yields and dividend yields in Schedule No. 3 of OTS Exhibit No. 1 reveals a direct relationship between these two variables. The correlation coefficient of the two arrays is .96, which indicates a very strong relationship.[1] This high correlation should be expected since all capital costs are extremely competitive. As a result, I believe it's important in determining an appropriate cost rate of common equity to recognize this

[1] Correlation coefficients range between 1 and -1. A correlation coefficient of 1 indicates a perfect positive relationship. A correlation coefficient of -1 indicates a perfect negative relationship. A correlation coefficient of 0 indicates no relationship exists.

relationship. Any potential impact related to a projected change in bond yields should be considered in recommending a representative dividend yield for the prospective period.

**Q. WHAT HAS BEEN THE HISTORICAL TREND OF PUBLIC UTILITY BOND YIELDS AND THE BAROMETER GROUP'S DIVIDEND YIELDS?**

A. The trend in "Aaa" rated bond yields and electric utility dividend yields, presented in Schedule 3, has been a steady decline over the past 23 years. Since 1981, "Aaa" rated corporate bond yields have decreased from 14.17 percent to 5.67 percent through 2003, or 850 basis points. Over the same time period, the six company barometer group's average dividend yield declined from 12.65 percent to 4.03 percent resulting in a decline of 862 basis points.

**Q. WHAT IS THE OUTLOOK FOR INTEREST RATES IN RELATION TO THE FORECASTED INFLATION RATE?**

A. Schedule No. 3 also presents short-term and long-term forecasts published by Blue Chip Financial Forecasts. Over the next two years, forecasting professionals are expecting T-Bill yields to be between 1.00 and 3.00 percent and forecasted inflation to be between 2.10 and 3.20 percent. As a result, the real rate of interest[2] is expected to be in the -2.20 to .60 percent range for this period. In relation to the

[2] The real rate of interest is the actual rate of interest minus the inflation rate.

historical average of 2 to 3 percent, the expected real rate of interest is at an extreme and clearly out of equilibrium.

Forecasting professionals are also expecting interest rates on long-term "Aaa" rated corporate bonds to remain fairly stable with an increase from 6.00 percent in the second quarter of 2004 to 6.90 percent by the third quarter of 2005. These forecasts reflect the belief that investors can expect real Gross Domestic Product (GDP) growth to remain brisk at between 3.7 to 4.5 percent over the next two years[3].

Investors' expectations are, however, continually changing and influenced by Federal Reserve policy. The Federal Reserve's tight monetary policy of recent years has done much to alleviate inflationary fear. However, with the recent emphasis on economic growth both in monetary and fiscal policy, inflationary fears have again become a concern.

**Q. WHAT IS THE OUTLOOK FOR INTEREST RATES FOR THE LONG-TERM?**

A. Schedule No. 3 of OTS Exhibit No. 1 further presents extended forecasts for the various interest rates. Expectations are for the "Aaa" corporate bond yield to increase to 7.6 percent from the current level of 6.00 percent. U.S. Treasury Bills are expected to increase to 4.3 percent from the current level of 1.0 percent.

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[3] Blue Chip Financial Forecasts, June 1, 2004.

**Q. IS THE EXPECTATION OF AN INCREASE OF THE LONG-TERM CORPORATE YIELDS OVER THE NEXT TEN YEARS TO 7.6 PERCENT INDICATIVE OF A LONG-TERM TREND?**

A. No. During the period 1993 to 2002, the "Aaa" Corporate Bond yield was in the range of 6 to 8 percent. The decrease to 5.67 percent in 2003 was aberrant to this range due to a soft economy and a very accommodative monetary policy. Thus an increase to 7.6 percent is still within the very stable rates experienced over the past 10 years and should not be construed as a general long-term trend resulting in an increase in capital cost rates.

## D. Discounted Cash Flow Analysis (DCF)

**Q. WILL YOU PLEASE EXPLAIN YOUR DCF ANALYSIS?**

A. My analysis employs the standard discrete DCF model, $k = D_1/P_0 + g$, where $D_1$ is the dividend expected during the year, $P_0$ is the current price of the stock, and g is the expected growth rate of dividends. For purposes of calculating a dividend yield applicable to the formula, $D_0/P_0$ (the current dividend divided by the current price) must be adjusted by ½ the expected growth rate[4] in order to account for changes in the dividend rate in period 1.

[4] The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain. It could occur next month or the twelfth month. On average it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by 1/2 the expected growth rate is appropriate.

**Q. PLEASE STATE THE RESULTS OF YOUR DISCOUNTED CASH FLOW (DCF) ANALYSIS.**

A. The following table summarizes the results of my DCF analysis:

| | Range | Average |
|---|---|---|
| Six Company Barometer Gp. | 8.84 - 9.00% | 8.92% |
| Nine Company Barometer Gp. | 8.40 - 8.55% | 8.48% |
| PPL Corporation | 8.84 - 9.06% | 8.95% |

Source: OTS Exhibit No. 1, Schedule 4, Pages 1, 2, and 3, Column 3.

**E. Dividend Yield**

**Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS THAT WERE USED IN YOUR DCF ANALYSIS?**

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

| | Dividend Yields (Adjusted) | | |
|---|---|---|---|
| | Spot 5/21/04 (%) | 52-week Average (%) | Average (%) |
| Six Company Barometer Gp. | 4.94 | 5.10 | 5.02 |
| Nine Company Barometer Gp. | 4.75 | 4.90 | 4.83 |
| PPL Corporation | 3.94 | 4.16 | 4.05 |

Source: OTS Exhibit No. 1, Schedule 4, Pages 1, 2, and 3, Column 1.

**F. Growth Rate**

**Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?**

A. To arrive at a representative dividend growth rate, I surveyed several series of projected growth rates. These growth rates are presented in OTS Exhibit No. 1,

Schedule No. 4, Page 4. My growth rate estimates are based on a survey of established forecasting entities including Value Line, Standard & Poor's (S&P), Thomson First Call, and Smart Money.

**Q. WHY HAVE YOU LIMITED YOUR SURVEY TO ANALYSTS' GROWTH RATE FORECASTS IN YOUR DETERMINATION OF AN OVERALL GROWTH RATE?**

A. The bulk of the research evidence has indicated analysts' growth forecasts are superior to historically oriented growth measures in forecasting growth. Forecasting professionals have already accounted for historical data in their estimates along with expectations of a wide array of economic variables. In my opinion, to give any weight to historical growth rates would result in a double count.

**Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR YOUR BAROMETER GROUP OF SIX ELECTRIC COMPANIES?**

A. I conclude that investors could expect to achieve a growth rate of 3.90 percent for the six company barometer group.

**Q. WHAT LEADS YOU TO BELIEVE THAT INVESTORS SHOULD EXPECT TO ACHIEVE A GROWTH RATE OF 3.90 PERCENT FOR THE SIX COMPANY BAROMETER GROUP?**

A. The expected growth rates for the six company barometer group are presented on Page 4 of Schedule 4. The barometer group average growth rates expected by Value Line, S&P, Thomson First Call, and Smart Money are 3.83, 4.00, 3.83, and 3.92 percent, respectively. From this information I conclude that an investor could reasonably expect to achieve a growth rate for the six company barometer group of 3.9 percent.

**Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR MR. MOUL'S BAROMETER GROUP OF NINE ELECTRIC COMPANIES?**

A. From the information on Page 4 of Schedule No. 4, I conclude that investors can expect to achieve a growth rate of 3.65 percent for Mr. Moul's barometer group of nine electric companies.

**Q. GIVEN THE LACK OF GROWTH RATES FOR CH ENERGY, CENTRAL VERMONT, AND GREEN MOUNTAIN POWER, HOW DID YOU DETERMINE A 3.65 PERCENT GROWTH RATE?**

A. I used Value Line's earnings growth estimate as a proxy for the other three sources. As a result, the average growth estimates for the four sources would be

3.61, 3.72, 3.61, and 3.67. From this information I conclude that an investor could reasonably expect to achieve a growth rate for the nine company barometer group of 3.65 percent.

**Q. WHAT DO YOU CONCLUDE TO BE A REASONABLE GROWTH RATE FOR PPL CORPORATION?**

A. From the information on Page 4 of Schedule No. 4, I conclude based upon the estimates that investors could expect to achieve a growth rate of 4.90 percent for PPL Corporation. The growth rates for PPL Corporation expected by Value Line, S&P, Thomson First Call, and Smart Money are 4.5, 5.0, 5.0, and 5.0 percent, respectively.

**Q. WHAT COST RATE OF COMMON EQUITY IS INDICATED FROM THE RESULTS OF YOUR DCF ANALYSIS?**

A. Given these representative dividend yields and my recommended growth rates, I calculated the DCF return with the results presented on Pages 1, 2, and 3 of Schedule No. 4. The six company barometer group results range from 8.84 to 9.00 percent. Mr. Moul's nine company barometer group results range from 8.40 to 8.55 percent. The results for PPL Corporation range from 8.84 to 9.06 percent.

**Q. WHAT COST RATE OF COMMON EQUITY DO YOU RECOMMEND FOR PPL?**

A. Based on the DCF results, I recommend that the appropriate cost rate of common equity for the electric industry, on average, is in the range of 8.75 to 9.00 percent. Based upon this range, I recommend an 8.75 percent cost rate of common equity for PPL.

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

A. The debt ratio as of December 31, 2004 for the six company barometer group was 58.25 percent (Schedule No. 2, Page 2 of OTS Exhibit No. 1). The debt ratio estimated at December 31, 2004 for PPL is 51.30 percent. This comparison of debt ratios indicates that PPL's prospective capital structure has less financial risk than the six company barometer group. In order to reflect differences in financial risk, it is appropriate to recommend the bottom of my recommended cost of common equity range of 8.75 percent.

**Q. IS THERE ANY OTHER REASON FOR SELECTING THE LOWER END OF YOUR RANGE?**

A. Yes. This is the first rate case since restructuring that is setting rates for only electric distribution. The DCF results for PPL Corporation and the barometer groups reflect both the electric distribution and their other more risky, unregulated

operations. As such, to recognize the lower business risk of just the electric distribution operations, the lower end of my range is most appropriate.

**Q. HAVE YOU TAKEN INTO CONSIDERATION MARKET PRESSURE AND SELLING AND ISSUANCE EXPENSES IN MAKING YOUR RECOMMENDATION?**

A. Yes. I have considered these items but have not made any adjustments to account for them. I believe that market pressure, selling and issuance expenses are an additional cost of capital that are incurred at the time of issuance. However, the current market price of common stock already reflects these items, as investors have already capitalized market pressure and issuance expenses in determining the value of the stock at the time of purchase. Since my analyses are market based, these items have been taken into consideration. As a result, I have made no additional adjustments to account for market pressure, selling, and issuance expenses.

## V. *Overall Weighted Cost of Capital*

**Q. WHAT IS THE OVERALL WEIGHTED COST OF CAPITAL FOR PPL?**

A. OTS Exhibit No. 1, Schedule No. 1, presents the calculation of PPL's overall weighted cost of capital. Based upon my 8.75 percent cost rate of common equity, the overall weighted cost of capital is 7.51 percent.

**Q. HAVE YOU TESTED YOUR COST OF CAPITAL RECOMMENDATION USING STANDARD & POOR'S (S&P) INTEREST COVERAGE CRITERIA?**

A. Yes. I have presented the interest coverage calculation in OTS Exhibit No. 1, Schedule No. 5. On a pre-tax basis, my recommendation results in an 10.50 percent weighted cost of capital for PPL. When divided by the weighted cost rate of debt of 3.30 percent, the resulting pre-tax interest coverage is 3.18 times. On Page 1, Schedule No. 6 of Exhibit No. 1, I have presented the results of an analysis of experienced interest coverages for the period of 1998 to 2003 for my barometer group of six electric companies. The following is a summary of those experienced coverages:

| | Range | Mean | 2003 |
|---|---|---|---|
| Six Company Group | 1.99 – 3.19 | 2.69 | 2.57 |

Source: OTS Exhibit No. 1, Schedule No. 6, Page 1.

The Company's pre-tax interest coverage of 3.18 times is at the top end of the group's range and far exceeds the group's coverage for 2003.

**Q. HOW DOES THE 3.18 TIMES PRE-TAX INTEREST COVERAGE COMPARE TO RECENT S&P'S BENCHMARKS FOR UTILITIES?**

A. PPL's 3.18 times interest coverage is at the top end of S&P's range required for a utility with a business position of 3 and a bond rating of "A-"[5].

## VII. Critique of PPL's Cost of Capital Testimony

**Q. PLEASE SUMMARIZE YOUR CRITIQUE OF PPL'S COST OF CAPITAL TESTIMONY.**

A. I have three primary areas of disagreement concerning Mr. Moul's cost of capital testimony.

- First, Mr. Moul has made several serious errors in his DCF analysis.
- Second, Mr. Moul has incorrectly given equal weight to the Risk Premium, CAPM, and Comparable Earnings methods in his recommendation.
- Third, Mr. Moul has incorrectly included a size premium and market to book adjustment in his CAPM analysis.

[5] PPL Statement No. 9, Page 13.

**Q. PLEASE EXPLAIN THE SPECIFIC ERRORS MR. MOUL MADE IN HIS DCF ANALYSIS.**

A. Mr. Moul inflated his DCF results by making an unwarranted ex-dividend adjustment to his dividend yield and an unwarranted 44 basis point adjustment to his overall DCF result to reflect differences in market value and book value.

**Q. WHY SHOULD THE EX-DIVIDEND ADJUSTMENT BE REJECTED AS AN APPROPRIATE ADJUSTMENT TO THE DCF RETURNS?**

A. I find this adjustment to be inappropriate for two reasons. First, I am not aware of any academic evidence that supports an ex-dividend adjustment to dividend yields in the context of the DCF model.

Secondly, there are no financial publications that provide ex-dividend adjusted yields to investors for their investment decision-making purposes. I believe that if this adjustment was an important input into investors' decision making process, the main stream financial publications would be providing it either on a daily or weekly basis.

**Q. WHY SHOULD MR. MOUL'S MARKET/BOOK ADJUSTMENT BE REJECTED?**

A. Mr. Moul's 44 basis point adjustment for market to book ratio (M/B) greater than 1.0 should be rejected for several reasons. First, the fact that electric companies' M/Bs are in excess of 1.0 is more an indicator that these companies are earning in

excess of the required rate of return, rather than underearning. An investor earning exactly his rate of return would price the stock at book value. Only when the earnings on book exceed the required rate of return will an investor bid the price of the stock above book value. The possibility of 44 basis points being added to the return investors currently require will give investors the incentive to bid prices even higher and cause the MB ratio to rise above the current level. The problem then becomes one of circularity. Following Mr. Moul's logic, he would have to claim an even higher adjustment for the ever-increasing M/B ratios with every future rate case.

**Q. IS MR. MOUL'S M/B ADJUSTMENT CONSISTENT WITH STANDARD FINANCE THEORY?**

A. No. In footnote 1 on Page 14 of his testimony, Mr. Moul states "the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value". This implies that high risk firms will have a lower M/B ratio and low risk firms will have a higher M/B ratio. Using Mr. Moul's M/B adjustment, the low risk firm would thus be rewarded more with a higher M/B adjustment in comparison to the high risk firm. This result is not consistent with standard finance theory of risk/reward where high risk firms require higher rates of return and low risk firms require lower rates of return.

**Q. ARE THERE ANY OTHER REASONS WHY YOU SHOULD QUESTION THE CREDABILITY OF MR. MOUL'S 44 BASIS POINT UPWARD ADJUSTMENT DUE TO A MARKET TO BOOK RATIO GREATER THAN 1.0?**

A. Yes. Mr. Moul's credability is also somewhat suspect since he has advocated in past PaPUC proceedings that a positive M/B adjustment should be made when the M/B ratio is less than 1. In Blue Mountain Consolidated Water Company, Docket No. R-78100686, Mr. Moul testified the rate of return should be inflated by up to 150 basis points in order to raise the M/B to 1.25. Mr. Moul, therefore, is quite aware of the impact on the M/B ratio of awarding a rate of return in excess of that required by investors. Strangely, his target must have changed since that case, otherwise he would be recommending in the instant case a negative M/B adjustment in order to achieve a M/B ratio of 1.25 in the future[6].

[6] The average M/B ratio for Mr. Moul's three company barometer group is currently 2.27. The average M/B ratio for my seven company barometer group is currently 2.48. Tradingday.com, smartmoney.com, February 10, 2004.

**Q. WHY SHOULD MR. MOUL'S METHODOLOGY, WHICH WEIGHTS THE RISK PREMIUM AND CAPM RESULT EQUALLY WITH THE DCF RESULTS, BE REJECTED FOR THE DETERMINATION OF THE APPROPRIATE COST OF CAPITAL?**

A. To understand why these rate of return methods should be rejected for cost of capital purposes, it must first be understood how investors use these methods in their decision making process. The Capital Asset Pricing Model (CAPM) and Risk Premium (RP) methods give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period the risk premiums were determined. By comparing CAPM and RP results with current expected equity returns (DCF results), an investor can make rational buy and sell decisions. When expected DCF returns are higher than those indicated by the CAPM and RP historical norms, an investor would have an incentive to buy, and vice versa.

The relevancy of these methods does not carry over from the investment decision making process to the regulatory process, because regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or in the future.[7]

[7] Mr. Moul's risk premium relied upon historical data back to 1928.

**Q. GIVEN THE FACT THAT ECONOMIC AND REGULATORY CONDITIONS TODAY ARE DIFFERENT FROM THE HISTORICAL PERIOD, HOW DOES THIS AFFECT THE RISK PREMIUMS USED IN MR. MOUL'S RP AND CAPM MODELS?**

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

**Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?**

A. Yes. An article, which appeared in the New York Times on February 18, 1992, summarizes a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French (OTS Exhibit No. 1, Schedule No. 7). Their study examined the importance of beta (CAPM's risk factor) in explaining returns on common stock. In CAPM theory, the higher a stock's beta, the higher the expected return on that

stock. They found that the model did not do well in predicting actual returns and suggest the use of more elaborate multi-factor models. As a result of this new information, I believe that rational investors will give less credibility to expected equity returns that are calculated using the simple CAPM model.

**Q. MR. MOUL ALSO INCLUDES A COMPARABLE EARNINGS MODEL (CEM) ANALYSIS IN HIS TESTIMONY. WHY SHOULD THIS METHOD BE REJECTED FOR RATEMAKING PURPOSES?**

A. I have several problems with Mr. Moul's CEM. First, Mr. Moul measured the historical earnings/book value ratios of non-utility companies. Mr. Moul has provided absolutely no evidence that these *accounting* returns for non-utilities bear any relationship to a *market* based return for electric utilities. Moreover, this method completely contradicts the premise underlying his other methods. In all of the other methods, Mr. Moul measured returns based upon market values, including the bond returns that he subtracted from the common stock returns to determine his risk premia.

**Q. WHAT IS THE COMMISSION'S TRACK RECORD ON THE COMPARABLE EARNINGS APPROACH?**

A. The Commission long ago recognized the problem with this method. With respect to the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility the Commission stated:

> The cardinal criticism of the comparable earnings approach is the problem of circularity. Witness Brennan's comparable earnings method requires the use of nonregulated companies. The use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding.

Pennsylvania Public Utility Commission v. Philadelphia Electric Co. (1980) 33 Pur4th 319, 341.

> NFGD employed comparable earnings as a check on the common equity cost rates produced by its other methodology. NFGD M.B. p. 170. NFGD did not use comparable earnings as a common equity cost rate determinant. Additionally, it was noted that comparable earnings are not market related but accounting related ratios.

PaPUC v. National Fuel Gas Distribution Corp., Docket No. R-00940021, Page 199, Order entered December 1, 1994.

**Q. ARE THERE ANY OTHER REASONS WHY MR. MOUL'S CEM RESULTS SHOULD BE REJECTED?**

A. Yes. The companies in Mr. Moul's CEM barometer group are simply not comparable to electric utilities in terms of their business risk/financial risk profile. Electric distribution utilities, being monopolies with very low business risk, are able to maintain higher financial risk profiles by employing more leverage. Conversely, Mr. Moul's CEM barometer group companies, being in an unregulated competitive environment with much higher business risk, must maintain lower financial risk profiles by employing minimal leverage. As

evidence of this, Schedule No. 8, Page 1, presents the debt ratios for the two barometer groups of electric companies compared to Mr. Moul's CEM barometer group. Mr. Moul's CEM barometer group has an average debt ratio of only 27.50%, compared to a debt ratio of 53.01% for Mr. Moul's Nine Company Group and 59.32% for the Six Company Group.

**Q. WHAT OTHER RATIO SHOWS THAT THE CEM BAROMETER GROUP IS NOT COMPARABLE TO THE ELECTRIC INDUSTRY?**

A. Schedule 8 also presents the percent of institutional holdings of the unregulated companies used in Mr. Moul's CEM analysis and the two barometer groups of electric companies. Institutional investors hold 59.50% of the shares of the unregulated companies compared to 41.35% and 42.08% for the two barometer groups of electric utilities. Clearly, institutional investors view the unregulated companies used in Mr. Moul's CEM analysis differently than they do the electric distribution companies.

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

A. Yes.

**Kevan L. Deardorff**

Educational and Professional Background

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

I am currently employed as a Fixed Utility Financial Analyst III. I have completed rate of return analyses in a large number of rate cases and assisted in the analyses of many electric, gas, water and telephone rate cases. I have prepared testimony concerning rate of return, discount rate, price cap, and merger benefits in the following cases:

| | |
|---|---|
| Keystone Water Company | R-822211-12 |
| | R-822215-19 |
| | R-822221 |
| Western Pennsylvania Water Company | R-832381 |
| Philadelphia Suburban Water Company | R-842592 |
| Duquesne Light Company | R-842583 |
| Western Pennsylvania Water Company | R-842621-25 |
| Riverton Consolidated Water Company | R-842675 |
| Keystone Water Company | R-842755-56 |
| | R-842759 |
| Equitable Gas Company | R-842769 |
| Western Pennsylvania Water Company | R-850096-97 |
| West Penn Power Company | R-850220 |
| Dauphin Consolidated Water Supply Co. | R-860350 |
| Western Pennsylvania Water Company | R-860397 |
| Philadelphia Electric Company (Gas Division) | R-870629 |
| National Fuel Gas Distribution Corp. | R-870719 |
| Western Pennsylvania Water Company | R-870825 |
| Philadelphia Suburban Water Company | R-870840 |
| Equitable Gas Company | R-880971 |
| Chartiers Natural Gas Company | R-891283 |
| Columbia Gas of Pennsylvania, Inc. | R-891468 |
| Arrowhead Public Service Corp. | R-891557 |
| Pennsylvania-American Water Co. | R-901652 |
| Citizens Utilities Water Company of Pennsylvania | R-901663 |
| Citizens Utilities Home Water Company | R-901664 |
| National Fuel Gas Distribution | R-901670 |
| York Water Company | R-901813 |

| | | |
|---|---|---|
| 1 | Columbia Gas of Pennsylvania, Inc. | R-901873 |
| 2 | National Fuel Gas Distribution Corp. | R-911912 |
| 3 | The Peoples Natural Gas Company | R-00922180 |
| 4 | York Water Company | R-00922168 |
| 5 | Pennsylvania & Southern Gas Company | R-00922312 |
| 6 | North Penn Gas Company | R-00922276 |
| 7 | North East Heat and Light Company | R-00922309 |
| 8 | Shenango Valley Water Company | R-00922420 |
| 9 | Mechanicsburg Water Company | R-00922502 |
| 10 | National Fuel Gas Distribution Corp. | R-00932548 |
| 11 | Roaring Creek Water Company | R-00932665 |
| 12 | Shenango Valley Water Company | R-00932798 |
| 13 | The Peoples Natural Gas Company | R-00932866 |
| 14 | Blue Mountain Consolidated Water Co. | R-00932873 |
| 15 | Allied Gas Company, et. al. | R-00932952 |
| 16 | National Fuel Gas Distribution Corp. | R-00942991 |
| 17 | Borough of Media Water Works | R-00943098 |
| 18 | Newtown Artesian Water Company | R-00943157 |
| 19 | Roaring Creek Water Company | R-00943177 |
| 20 | Borough of Schuylkill Haven | R-00943156 |
| 21 | Pennsylvania Power & Light Company | R-00943271 |
| 22 | National Fuel Gas Distribution Corp. | R-00953299 |
| 23 | Frontier Companies | P-00951005 |
| 24 | PFG Gas, Inc. and North Penn Gas Company | R-00953524 |
| 25 | Commonwealth Telephone Company | P-00961024 |
| 26 | PECO Energy Company | R-00973877 |
| 27 | PECO Energy Company | R-00973953 |
| 28 | Pennsylvania Power & Light Company | R-00973954 |
| 29 | Ironton Telephone Company | P-00971182 |
| 30 | Metropolitan Edison Company | R-00974008 |
| 31 | Pennsylvania Electric Company | R-00974009 |
| 32 | Pennsylvania Power Company | R-00974149 |
| 33 | PG Energy, Inc. | R-00984280 |
| 34 | ALLTEL Pennsylvania, Inc. | P-00981423 |
| 35 | Pennsylvania Telephone Association Small Group | P-00981425, et al |
| 36 | United Telephone Company of Pennsylvania | P-00981410 |
| 37 | City of Lancaster Water Fund | R-00984567 |
| 38 | York Water Company | R-00994605 |
| 39 | Pittsburgh Thermal, L.P. | R-00994641 |
| 40 | PECO Energy Company | A-110550F0147 |
| 41 | PG Energy | R-00005119 |
| 42 | City of Lancaster Sewer Fund | R-00005109 |
| 43 | PFG Gas, Inc. and North Penn Gas Company | R-00005277 |

| | | |
|---|---|---|
| 1 | Emporium Water Company | R-00005050 |
| 2 | T.W. Phillips Gas and Oil Company | R-00005459 |
| 3 | Verizon North, Inc. | P-00001854 |
| 4 | Metropolitan Edison Company | P-00001860 |
| 5 | Pennsylvania Electric Company | P-00001861 |
| 6 | Philadelphia Gas Works | R-00006042 |
| 7 | Pennsylvania American Water Company | R-00016339 |
| 8 | Wellsboro Electric Company | R-00016356 |
| 9 | Verizon Pennsylvania Inc. | R-00016683 |
| 10 | Philadelphia Suburban Water Company | R-00016750 |
| 11 | Philadelphia Gas Works – Extraordinary Rate Relief | R-00017034F |
| 12 | Verizon Pennsylvania Inc. | R-00930715F0002 |
| 13 | York Water Company | R-00027975 |
| 14 | National Fuel Gas Distribution Corp. | R-00038168 |
| 15 | Pennsylvania American Water Company | R-00038304 |
| 16 | Aqua Pennsylvania, Inc. | R-00038805 |
| 17 | Duquesne Light Company | P-00032071 |

OTS Exhibit No. 1
Witness: Kevan L. Deardorff
Date: June 29, 2004

DOCUMENT

8/10/04 Hbg PX

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Exhibit to Accompany**

**the**

**Direct Testimony**

**of**

**Kevan L. Deardorff**

**Office of Trial Staff**



**Concerning:**

**Rate of Return**

PPL Electric Utilities Corporation
OTS Recommended Weighted Cost of Capital
at December 31, 2004

| | | Capital Structure (1) | Cost Rates (2) | Weighted Cost of Capital (3=1x2) |
|---|---|---|---|---|
| (1) | Long-Term Debt | 51.30% | 6.43% | 3.30% |
| (2) | Preferred Stock | 1.83% | 6.19% | 0.11% |
| (3) | Common Equity | 46.87% | 8.75% | 4.10% |
| (4) | Total | 100.00% | | 7.51% |

PPL Electric Corporation
Capitalization Structure Comparison
at December 31, 2003

| | | PPL Electric Corporation Dec. 31, 2003 (1) | Nine Company Barometer Group Dec. 31, 2003 (2) | Six Company Barometer Group Dec. 31, 2003 (3) |
|---|---|---|---|---|
| (1) | Long-Term Debt | 53.88% | 51.60% | 57.24% |
| (2) | Preferred Stock | 1.74% | 2.20% | 2.02% |
| (3) | Common Equity | 44.38% | 46.20% | 40.74% |
| (4) | Total | 100.00% | 100.00% | 100.00% |

Source: PPL Exhibit PRM-1, Page 11, Schedule 6
Company annual reports

PPL Electric Corporation
Capitalization Structure Comparison
estimated at December 31, 2004

| | | PPL Electric Corporation Dec. 31, 2004 (1) | Nine Company Barometer Group Dec. 31, 2004 (2) | Six Company Barometer Group Dec. 31, 2004 (3) |
|---|---|---|---|---|
| (1) | Long-Term Debt | 51.30% | 52.33% | 58.25% |
| (2) | Preferred Stock | 1.83% | 1.94% | 1.75% |
| (3) | Common Equity | 46.87% | 45.72% | 40.00% |
| (4) | Total | 100.00% | 100.00% | 100.00% |

Source: PPL Exhibit PRM-1, Page 11, Schedule 6
Value Line Investment Survey, March 5, 2004

Comparison of Key Economic Variables to the Dividend Yields for the
Barometer Group of Six Electric Companies
for 1981 to 2003 and Estimates for 2004 to 2014

| | Year | Moody's 'Aaa' Corporate Bond Yield | U.S. Treasury Bills | Prime Rate | CPI Percent Change | Barometer Group Dividend Yields |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| (1) | 1981 | 14.17 | 14.03 | 18.87 | 8.90 | 12.65 |
| (2) | 1982 | 13.79 | 10.69 | 14.86 | 3.80 | 11.60 |
| (3) | 1983 | 12.04 | 8.63 | 10.79 | 3.80 | 10.38 |
| (4) | 1984 | 12.71 | 9.58 | 12.04 | 4.00 | 11.28 |
| (5) | 1985 | 11.37 | 7.48 | 9.93 | 3.80 | 9.23 |
| (6) | 1986 | 9.02 | 5.98 | 8.33 | 1.10 | 7.23 |
| (7) | 1987 | 9.38 | 5.82 | 8.21 | 4.40 | 7.88 |
| (8) | 1988 | 9.71 | 6.69 | 9.32 | 4.40 | 8.45 |
| (9) | 1989 | 9.26 | 8.12 | 10.87 | 4.60 | 6.68 |
| (10) | 1990 | 9.32 | 7.51 | 10.01 | 6.10 | 6.72 |
| (11) | 1991 | 8.77 | 5.42 | 8.46 | 3.10 | 6.43 |
| (12) | 1992 | 8.14 | 3.45 | 6.25 | 2.90 | 5.65 |
| (13) | 1993 | 7.22 | 3.02 | 6.00 | 2.70 | 5.88 |
| (14) | 1994 | 7.96 | 4.29 | 7.15 | 2.70 | 7.30 |
| (15) | 1995 | 7.59 | 5.51 | 8.83 | 2.50 | 6.77 |
| (16) | 1996 | 7.37 | 5.02 | 8.27 | 3.30 | 6.75 |
| (17) | 1997 | 7.26 | 5.07 | 8.44 | 1.70 | 5.43 |
| (18) | 1998 | 6.53 | 4.81 | 8.35 | 1.60 | 4.68 |
| (19) | 1999 | 7.04 | 4.66 | 8.00 | 2.70 | 3.97 |
| (20) | 2000 | 7.62 | 5.85 | 9.23 | 3.40 | 4.78 |
| (21) | 2001 | 7.08 | 3.45 | 6.99 | 1.60 | 3.83 |
| (22) | 2002 | 6.49 | 1.62 | 4.67 | 2.40 | 3.32 |
| (23) | 2003 | 5.67 | 1.02 | 4.12 | 1.90 | 4.03 |
| | Recent Forecasts: | | | | | |
| (24) | 2004-2nd Qtr | 6.00 | 1.00 | 4.00 | 3.20 | |
| (25) | 2004-3rd Qtr | 6.30 | 1.40 | 4.40 | 2.30 | |
| (26) | 2004-4th Qtr | 6.40 | 1.70 | 4.70 | 2.10 | |
| (27) | 2005-1st Qtr | 6.60 | 2.20 | 5.10 | 2.30 | |
| (28) | 2005-2nd Qtr | 6.80 | 2.60 | 5.50 | 2.30 | |
| (29) | 2005-3rd Qtr | 6.90 | 3.00 | 6.00 | 2.40 | |
| | Extended Forecasts: | | | | | |
| (30) | 2005 | 6.90 | 2.90 | 5.80 | 2.30 | |
| (31) | 2006 | 7.30 | 3.80 | 6.80 | 2.40 | |
| (32) | 2007 | 7.50 | 4.20 | 7.10 | 2.40 | |
| (33) | 2008 | 7.60 | 4.30 | 7.30 | 2.50 | |
| (34) | 2009 | 7.60 | 4.30 | 7.30 | 2.40 | |
| (35) | 2010-14 | 7.50 | 4.20 | 7.20 | 2.50 | |

Note: Correlation of C1 and C5 = .96.

*Sources:* *Economic Indicators, March, 2004*
Blue Chip Financial Forecasts, June 1, 2004
Moody's Bond Record, Various Issues

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Six Electric Companies

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 5/21/04) | 4.94% | 3.90% | 8.84% |
| (2) | Spot Price (ending 5/21/04) | 5.10% | 3.90% | 9.00% |
| (3) | Average: | 5.02% | 3.90% | 8.92% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, March 5, 2004
Barron's, May 24, 2004

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Nine Electric Companies

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 5/21/04) | 4.75% | 3.65% | 8.40% |
| (2) | Spot Price (ending 5/21/04) | 4.90% | 3.65% | 8.55% |
| (3) | Average: | 4.83% | 3.65% | 8.48% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, March 5, 2004
Barron's June, May 21, 2004

Expected Market Cost Rate of Equity
Using Data for PPL Corporation

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 5/21/04) | 3.94% | 4.90% | 8.84% |
| (2) | Spot Price (ending 5/21/04) | 4.16% | 4.90% | 9.06% |
| (3) | Average: | 4.05% | 4.90% | 8.95% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, March 5, 2004
Barron's, May 24, 2004

## Expected Growth Rates
## for the Barometer Group of Electric Companies

| | Company | Value Line Dividend Growth (1) | Value Line Earnings Growth (2) | S & P Earnings Growth (3) | First Call Earnings Growth (4) | Smart Money Earnings Growth (5) |
|---|---|---|---|---|---|---|
| [1] | CH Energy Group | 0.0 | 0.0 | - | - | - |
| [2] | Central Vermont PS | 3.5 | 6.0 | - | - | - |
| [3] | Consolidated Edison | 1.0 | 0.0 | 3.0 | 2.5 | 2.8 |
| [4] | Duquesne Light Holdings | -4.0 | 9.0 | 4.0 | 4.0 | 5.0 |
| [5] | Energy East Corp. | 4.0 | -1.0 | 5.0 | 4.0 | 4.7 |
| [6] | Green Mountain Power | 11.0 | 3.5 | - | - | - |
| [7] | Northeast Utilities | 8.5 | 9.5 | 4.0 | 4.5 | 4.0 |
| [8] | NSTAR | 2.5 | 3.0 | 4.0 | 5.0 | 4.3 |
| [9] | Pepco Holdings | 3.5 | 2.5 | 4.0 | 3.0 | 2.7 |
| [10] | Nine Company Average | 3.33 | 3.61 | - | - | - |
| [11] | Six Company Average | 2.58 | 3.83 | 4.00 | 3.83 | 3.92 |
| [12] | PPL Corporation | 3.50 | 4.50 | 5.00 | 5.00 | 5.00 |

Sources: Value Line Investment Survey, March 5, 2004
Internet, Finance.yahoo.com and Smartmoney.com, May 24, 2004
Standard & Poor's Earnings Guide, May, 2004

PPL Electric Utilities Corporation
Interest Coverage

| | | Capital Structure (1) | Cost Rates (2) | Weighted Cost of Capital (3= 1x2) | Effective Tax Rate Complement(1) (4) | Pre-Tax Cost of Capital (5=3/4) |
|---|---|---|---|---|---|---|
| (1) | Debt | 51.30% | 6.43% | 3.30% | | 3.30% |
| (2) | Preferred Stock | 1.83% | 6.19% | 0.11% | 0.5851 | 0.19% |
| (3) | Common Equity | 46.87% | 8.75% | 4.10% | 0.5851 | 7.01% |
| (4) | Total | 100.00% | | 7.51% | | 10.50% |

(5) Pre-Tax Coverage: 10.50/3.30 = 3.18

(6) Notes: (1) Effective income tax rate assumed to be 41.493%.
[35% Fed. Inc. Tax + (9.99% State Inc. Tax x (1-.35)].

Historic Interest Coverage Ratios
for the Barometer Group of Electric Companies for 1998-2003 (1)

| | Company | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| [1] | Consolidated Edison | 4.46 | 4.19 | 3.17 | 3.57 | 3.34 | 2.89 |
| [2] | Duquesne Light Holdings | 3.77 | 3.03 | 2.69 | -1.00 | 1.54 | 3.56 |
| [3] | Energy East Corp. | 3.71 | 4.41 | 3.59 | 2.48 | 1.99 | 2.40 |
| [4] | Northeast Utilities | 0.61 | 1.57 | 2.27 | 2.60 | 1.89 | 1.77 |
| [5] | NSTAR | 3.32 | 2.59 | 2.45 | 1.67 | 2.35 | 2.77 |
| [6] | Pepco Holdings, Inc. | 3.27 | 2.59 | 4.14 | 2.60 | 2.43 | 2.03 |
| [7] | Barometer Group Average | 3.19 | 3.06 | 3.05 | 1.99 | 2.26 | 2.57 |

Note: (1) Pre-tax basis

Source: OTS-RR-7.xls (attached as page 2)
Annual reports to shareholders

OTS-RR-7.xls

Pre-tax Interest Coverage, excl. AFUDC
1998-2002, Inclusive

| | 2002 | | 2001 | | 2000 | | 1999 | | 1998 | | Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Electric Group | | | | | | | | | | | | |
| CH ENERGY GROUP INC | 3.42 | x | 2.67 | x | 3.64 | x | 3.68 | x | 3.90 | x | 3.46 | x |
| CENTRAL VERMONT PUB SERV | 3.55 | x | 1.79 | x | 3.05 | x | 3.21 | x | 1.38 | x | 2.60 | x |
| CONSOLIDATED EDISON INC | 3.34 | x | 3.57 | x | 3.17 | x | 4.19 | x | 4.46 | x | 3.75 | x |
| DQE INC | 1.54 | x | (1.00) | x | 2.69 | x | 3.03 | x | 3.77 | x | 2.01 | x |
| ENERGY EAST CORP | 1.99 | x | 2.48 | x | 3.59 | x | 4.41 | x | 3.71 | x | 3.24 | x |
| GREEN MOUNTAIN POWER CORF | 3.73 | x | 3.54 | x | 0.93 | x | 1.72 | x | 0.44 | x | 2.07 | x |
| NORTHEAST UTILITIES | 1.89 | x | 2.60 | x | 2.27 | x | 1.57 | x | 0.61 | x | 1.79 | x |
| NSTAR | 2.35 | x | 1.67 | x | 2.45 | x | 2.59 | x | 3.32 | x | 2.48 | x |
| PEPCO HOLDINGS INC | 2.43 | x | 2.60 | x | 4.14 | x | 2.77 | x | 3.27 | x | 3.04 | x |
| Average | 2.69 | x | 2.21 | x | 2.88 | x | 3.02 | x | 2.76 | x | 2.71 | x |
| Gas Group | | | | | | | | | | | | |
| AGL RESOURCES INC | 2.87 | x | 2.72 | x | 3.22 | x | 3.26 | x | 3.32 | x | 3.08 | x |
| ATMOS ENERGY CORP | 2.55 | x | 2.83 | x | 2.28 | x | 1.74 | x | 3.45 | x | 2.57 | x |
| ENERGEN CORP | 3.05 | x | 2.94 | x | 2.55 | x | 2.11 | x | 2.12 | x | 2.55 | x |
| KEYSPAN CORP | 3.07 | x | 2.29 | x | 3.54 | x | 4.17 | x | (1.35) | x | 2.34 | x |
| NEW JERSEY RESOURCES | 6.46 | x | 5.16 | x | 4.83 | x | 4.50 | x | 4.31 | x | 5.05 | x |
| PIEDMONT NATURAL GAS CO | 3.34 | x | 3.27 | x | 3.53 | x | 3.69 | x | 3.80 | x | 3.53 | x |
| SOUTH JERSEY INDUSTRIES | 3.40 | x | 2.96 | x | 2.78 | x | 2.61 | x | 2.15 | x | 2.78 | x |
| WGL HOLDINGS INC | 2.58 | x | 3.81 | x | 4.01 | x | 3.94 | x | 3.85 | x | 3.64 | x |
| Average | 3.42 | x | 3.25 | x | 3.34 | x | 3.25 | x | 2.71 | x | 3.19 | x |
| Standard & Poor's Public Utilities | | | | | | | | | | | | |
| ALLEGHENY ENERGY INC | | x | 3.44 | x | 3.18 | x | 3.44 | x | 3.42 | x | 3.37 | x |
| AMEREN CORP | 3.83 | x | 4.89 | x | 5.20 | x | 4.79 | x | 4.58 | x | 4.66 | x |
| AMERICAN ELECTRIC POWER | 1.31 | x | 2.63 | x | 1.95 | x | 2.50 | x | 2.91 | x | 2.26 | x |
| CENTERPOINT ENERGY INC | 1.79 | x | 2.96 | x | 2.44 | x | 5.56 | x | 0.68 | x | 2.69 | x |
| CINERGY CORP | 2.80 | x | 3.40 | x | 3.76 | x | 3.53 | x | 2.50 | x | 3.20 | x |
| CMS ENERGY CORP | 0.19 | x | 0.39 | x | 1.07 | x | 1.50 | x | 1.84 | x | 1.00 | x |
| CONSOLIDATED EDISON INC | 3.34 | x | 3.57 | x | 3.17 | x | 4.19 | x | 4.46 | x | 3.75 | x |
| CONSTELLATION ENERGY GRP I | 3.72 | x | 1.47 | x | 3.28 | x | 3.10 | x | 2.99 | x | 2.91 | x |
| DTE ENERGY CO | 2.00 | x | 1.47 | x | 2.42 | x | 2.60 | x | 2.89 | x | 2.28 | x |
| DOMINION RESOURCES INC | 3.16 | x | 1.92 | x | 1.58 | x | 2.41 | x | 2.43 | x | 2.30 | x |
| DUKE ENERGY CORP | 2.41 | x | 4.96 | x | 4.07 | x | 3.16 | x | 4.96 | x | 3.91 | x |
| EDISON INTERNATIONAL | 2.10 | x | 3.41 | x | (1.00) | x | 2.02 | x | 2.55 | x | 1.82 | x |
| EL PASO CORP | (0.27) | x | 1.22 | x | 2.66 | x | 0.34 | x | 2.41 | x | 1.27 | x |
| ENTERGY CORP | 2.34 | x | 2.49 | x | 2.95 | x | 2.56 | x | 2.22 | x | 2.51 | x |
| EXELON CORP | 3.62 | x | 3.03 | x | 2.44 | x | 3.33 | x | 3.35 | x | 3.15 | x |
| FPL GROUP INC | 3.78 | x | 4.46 | x | 4.79 | x | 5.66 | x | 3.98 | x | 4.53 | x |
| FIRSTENERGY CORP | 2.45 | x | 3.25 | x | 3.05 | x | 3.02 | x | 2.51 | x | 2.86 | x |
| KEYSPAN CORP | 3.07 | x | 2.29 | x | 3.54 | x | 4.17 | x | (1.35) | x | 2.34 | x |
| KINDER MORGAN INC | 3.71 | x | 2.82 | x | 2.24 | x | 1.96 | x | 1.37 | x | 2.42 | x |
| NICOR INC | 5.75 | x | 5.70 | x | 2.21 | x | 5.22 | x | 4.81 | x | 4.74 | x |
| NISOURCE INC | 2.20 | x | 1.64 | x | 1.88 | x | 2.41 | x | 3.35 | x | 2.30 | x |
| PG&E CORP | 0.95 | x | 2.43 | x | (5.60) | x | 1.37 | x | 2.66 | x | 0.36 | x |
| PPL CORP | 2.13 | x | 2.25 | x | 3.15 | x | 3.45 | x | 3.88 | x | 2.97 | x |
| PEOPLES ENERGY CORP | 3.40 | x | 3.06 | x | 3.38 | x | 4.34 | x | 4.14 | x | 3.66 | x |
| PINNACLE WEST CAPITAL | 2.64 | x | 3.80 | x | 3.95 | x | 3.63 | x | 3.36 | x | 3.48 | x |
| PROGRESS ENERGY INC | 1.59 | x | 1.51 | x | 3.28 | x | 4.29 | x | 4.59 | x | 3.05 | x |
| PUBLIC SERVICE ENTRP | 1.79 | x | 2.46 | x | 2.92 | x | 3.25 | x | 2.92 | x | 2.67 | x |
| SEMPRA ENERGY | 3.24 | x | 3.18 | x | 3.36 | x | 3.55 | x | 3.14 | x | 3.29 | x |
| SOUTHERN CO | 3.79 | x | 3.24 | x | 2.85 | x | 2.63 | x | 2.41 | x | 2.98 | x |
| TECO ENERGY INC | 2.21 | x | 2.55 | x | 2.59 | x | 3.30 | x | 3.70 | x | 2.87 | x |
| TXU CORP | 1.32 | x | 1.53 | x | 1.80 | x | 1.93 | x | 1.93 | x | 1.70 | x |
| WILLIAMS COS INC | 0.43 | x | 2.86 | x | 2.41 | x | 1.48 | x | 1.50 | x | 1.74 | x |
| XCEL ENERGY INC | (1.39) | x | 2.22 | x | 2.15 | x | 2.18 | x | 3.00 | x | 1.63 | x |
| Average | 2.36 | x | 2.80 | x | 2.52 | x | 3.12 | x | 2.91 | x | 2.74 | x |

N.Y. Times Tue. Feb 18, 1992



**Market Place**

# A Study Shakes Confidence In the Volatile-Stock Theory

By ERIC N. BERG

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

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

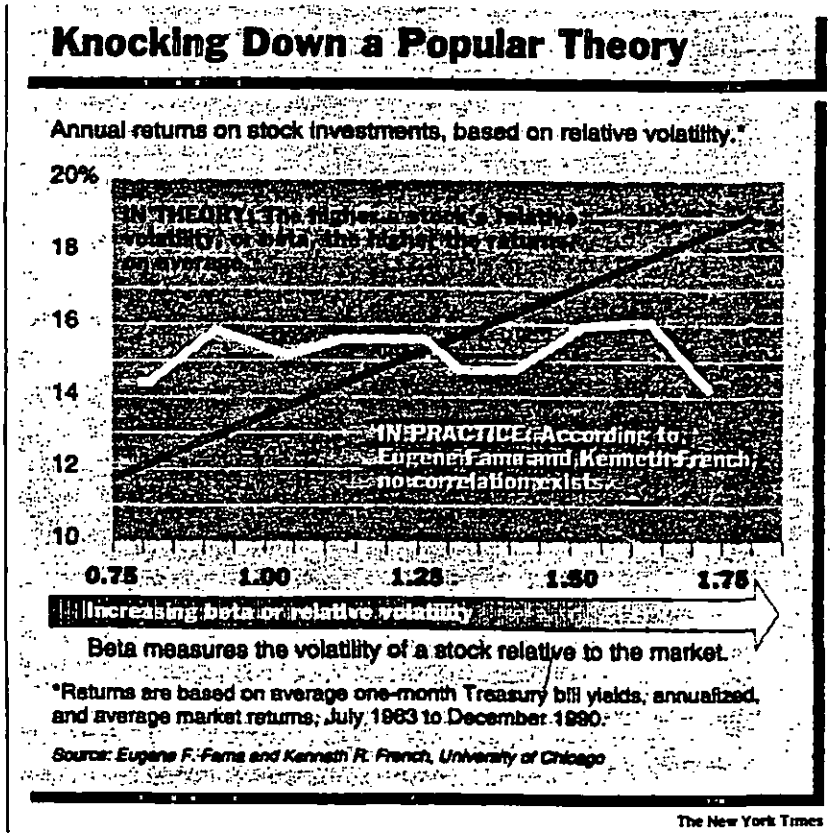
The importance of "beta," the investment community's term for a stock's volatility relative to the market, has long been under challenge. But it is still closely watched by analysts, and business students are still taught that they can earn higher returns by buying stocks whose swings are wider than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

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

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

If Professors Fama and French

*Continued on Page D6*



# A Study Shakes Confidence In the Volatile-Stock Theory

*Continued From First Business Page*

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

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

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

• • •

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

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

• • •

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

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

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

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

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

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

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

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

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

# Equity Issues This Week

*Comparison of Debt to Total Capital Ratios and Percent Institutional Holdings for Mr. Moul's CEM Group*
Compared to Mr. Moul's Electric Group and the Group of Six Electric Companies

| | Company | Debt Ratio (1) | Percentage Institutional (2) |
|---|---|---|---|
| [1] | CEM Group(a) | 27.50% | 59.50% |
| [2] | Mr. Moul's Electric Group | 53.01% | 41.35% |
| [3] | Six Company Electric Group | 59.32% | 42.08% |

Source: Value Line Investment Survey

Note: (a) Referrence OTS Exhibit No. 1, Schedule 8, Page 2.

Debt to Total Capital Ratios and Percent Institutional Holdings for the CEM Group
at December 31, 2003

| | Company | | Debt Ratio (1) | Percentage Institutional (2) |
|---|---|---|---|---|
| [1] | ABM Industries Inc. | | 0.00% | 64.73% |
| [2] | Applied Ind. Techn. | | 20.34% | 68.25% |
| [3] | Arrow Int'l | | 0.94% | 33.99% |
| [4] | Banat Corp. | | 15.29% | 83.48% |
| [5] | Berkley (W. R.) | | 33.62% | 78.11% |
| [6] | Campbell Soup | | 85.32% | 37.53% |
| [7] | ConAgra Foods | | 53.86% | 56.90% |
| [8] | Dean Foods | | 50.67% | 77.54% |
| [9] | Franklin Electric | | 7.22% | 52.11% |
| [10] | General Mills | | 64.29% | 56.41% |
| [11] | Harland (John H.) | | 32.34% | 79.79% |
| [12] | Hormel Foods | | 23.99% | 26.74% |
| [13] | Int'l Flavors & Frag. | | 49.13% | 76.17% |
| [14] | Kellogg | | 74.72% | 82.38% |
| [15] | Liberty Corp. | | 0.00% | 54.50% |
| [16] | Markel Corp. | | 28.54% | 71.83% |
| [17] | Matthews Int'l | | 18.20% | 64.80% |
| [18] | McClatchy Co. | | 14.42% | 37.64% |
| [19] | McCormick & Co. | | 37.27% | 65.72% |
| [20] | National Presto Ind. | | 0.00% | 45.44% |
| [21] | Northrop Grumman | | 24.71% | 83.97% |
| [22] | Old Nat'l Bancorp | | 71.56% | 19.21% |
| [23] | Pulitzer Inc. | | 26.63% | 41.45% |
| [24] | Quaker Chemical | | 12.00% | 54.01% |
| [25] | Riviana Foods | | 0.88% | 29.18% |
| [26] | RLI Corp. | | 8.02% | 81.25% |
| [27] | Ruddick Corp. | | 24.13% | 52.17% |
| [28] | Selective Ins. Group | | 13.39% | 66.83% |
| [29] | Sensient Techn. | | 47.55% | 83.54% |
| [30] | ServiceMaster Co. | | 49.03% | 52.21% |
| [31] | Smucker (J.M.) | | 10.11% | 46.99% |
| [32] | St. Joe Corp. | | 43.94% | 46.36% |
| [33] | Tennant Co. | | 3.66% | 67.54% |
| [34] | Thomas Inds. | | 21.13% | 53.21% |
| [35] | Transatlantic Hldgs. | | 0.00% | 95.27% |
| [36] | Universal Corp. | | 49.79% | 82.09% |
| [37] | Weis Markets | | 0.00% | 19.24% |
| [38] | Wendy's Int'l | | 28.37% | 72.35% |
| [39] | | Average | 27.50% | 59.50% |

Source: Value Line Investment Survey

OTS Statement No. 1-SR
Witness: Kevan L. Deardorff
Date: August 5, 2004
8/10/04 Mbg JTC



**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Surrebuttal Testimony**

**of**

**Kevan L. Deardorff**

**Office of Trial Staff**



**Concerning:**

**Rate of Return**

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

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

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?**

A. Yes, I have. Please refer to OTS Statement No. 1 and OTS Exhibit No. 1.

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. I have three reasons for presenting surrebuttal testimony. First, I want to update my recommended rate of return to account for changes that have occurred since I prepared my direct testimony. Second, I want to briefly respond to Mr. Paul Moul's rebuttal testimony, PPLEU Statement No. 9-R. Finally, I want to address remarks made by Ms. Julie M. Cannell in PPLEU Statement No. 10-R concerning inflation and rising interest rates.

**Q. WHAT IS YOUR UPDATED RECOMMENDED RATE OF RETURN AND HOW DID YOU CALCULATE IT?**

A. My updated recommended overall rate of return is 7.63 percent. OTS Exhibit No. 1-Sr, Schedule No. 1 (Updated) presents this calculation. The increase in the overall rate of return is the result of my recommended cost of equity increasing

from 8.75 to 9.00 percent. This revision was necessary to account for changes that have occurred in both analysts' growth forecasts and market data.

**Q. PLEASE DESCRIBE THE UPDATES TO YOUR DCF ANALYSIS.**

A. My updated recommended overall rate of return is 7.63 percent. OTS Exhibit No. 1-SR, Schedule No. 4, Pages 1, 2, and 3 (Updated). The primary DCF results for the six company barometer group are in the range of 9.04 to 9.06 percent. The DCF results for the Nine Company Barometer Group are 8.76 percent. The primary DCF results for PPL Corporation are in the range of 8.88 to 9.07 percent.

**Q. HAVE YOU TESTED YOUR UPDATED COST OF CAPITAL RECOMMENDATION USING INTEREST COVERAGE CRITERIA?**

A. Yes. I have presented the updated interest coverage calculation in OTS Exhibit No. 1-SR, Schedule No. 3, Page 1, (Updated). My recommended pre-tax weighted cost of capital is 10.70 percent. When divided by the weighted cost rate of debt 3.30 percent, this weighted cost of capital results in pre-tax interest coverage of 3.24 times.

**Q. HOW DOES 3.24 TIMES PRE-TAX INTEREST COVERAGE COMPARE TO STANDARD & POOR'S BENCHMARKS FOR UTILITIES?**

A. PPL's 3.24 times interest coverage is approximately in the middle of S&P's requirement for an "A-" rating and slightly below the lower end of S&P's range of coverage required for a utility with a business position of 4 and a bond rating of "A".

**Q. ARE YOU CONCERNED THAT YOUR RECOMMENDATION DOES NOT RESULT IN A COVERAGE RATIO CONSISTENT WITH AN "A" BOND RATING?**

A. No. The coverage ratio is the result of PPL's capital structure. PPL employs a capital structure that is not consistent with an "A" bond rating. PPL's debt ratio of 51.30 percent exceeds the top end of S&P's range of 43.0 to 49.5 percent required for a utility with a business position of 4 to maintain a bond rating of "A". This debt ratio is more consistent with a bond rating of "BBB".

**Q. WHAT WOULD PPL'S COVERAGE RATIO BE IF IT MAINTAINED A DEBT RATIO CONSISTENT WITH AN "A" BOND RATING?**

A. Schedule 5, Page 2, of Exhibit No. 1-SR presents the interest coverage calculation using as a hypothetical the midpoint of S&P's recommended debt ratio for a utility with a business position of 4 and a bond rating of "A". If PPL maintained a debt ratio of 46.25 percent, my recommended cost of equity of 9.00 percent would

result in a pre-tax interest coverage ratio of 3.75 times. This coverage would be slightly above the midpoint of S&P's required rang of 3.3 to 4.0 for a utility with a business position of 4 and a bond rating of "A". It is apparent from this exercise that it is not the responsibility of only the Commission to support a reasonable debt rating, but the Company has equal responsibility in maintaining a strong profile.

**Q. MR. MOUL STATES IN A FOOTNOTE ON PAGE 27 OF HIS REBUTTAL TESTIMONY THAT YOU MISPLACED THE DECIMAL POINT IN THE VALUE LINE EXPECTED DIVIDEND GROWTH RATE FOR PEPCO. DOES THIS ERROR HAVE ANY IMPACT ON YOUR RECOMMENDATION?**

A. No. In my original testimony, I only used expected earnings growth rates and did not use Value Line expected growth in dividends to arrive at my recommended growth rate[1]. As a result, Mr. Moul's correcting this error has no impact on my analysis. I only included the dividend growth rates for illustrative purposes since Mr. Moul relied heavily on them in his analysis. Mr. Moul has attempted to give credence to his analysis by suggesting that I relied on Value Line expected dividend growth rates in his correction of the 35% dividend growth rate.

[1] OTS Statement No. 1, Page 19

**Q. WHY DID YOU NOT USE VALUE LINE'S FIVE YEAR FORECASTED DIVIDEND GROWTH RATES IN YOUR ANALYSIS?**

A. The forecasts that Value Line's methodology is producing are suspect. Two examples will illustrate this point. As a first example, consider Value Line's five year dividend forecast for Duquesne Light of -4.0 percent. Value Line's data base shows that dividends paid in 2003 were $1.00 and are expecting to pay $1.00 in 2004 and to increase to $1.04 in five years. The data clearly shows an incremental increase in the future but Value Line's perverse methodology of factoring in a decrease that occurred in 2002 clearly distorts the forecast into a negative number.

**Q. DID YOU FIND ANY OTHER PERVERSIONS IN VALUE LINE'S CALCULATIONS OF FORECASTED DIVIDEND GROWTH?**

A. Yes. Value Line forecasted a dividend growth rate of 35 percent for PEPCO in the March 5, 2004 issue but later lowered this forecast to 16 percent in the June 4, 2004 issue. The fact that these two forecasts are based on the same identical set of dividend cash flows makes either result questionable. Second, the calculations are based on an assumption that PEPCO only started paying dividends after the merger of PEPCO and Conectiv on August 1, 2002. Value Line's growth rate calculations were based on PEPCO shareholders receiving dividends of $0.00 in 2001, $.42 in 2002, and $1.00 in 2003. The actual records show that PEPCO shareholders received dividends of $1.00 in 2001, $1.00 in 2002, and $1.00 in 2003. Any calculations based on this clearly factual error will definitely yield

useless results. It is no wonder that Mr. Moul was able to calculate such large growth rates in footnote 5 on Page 27 of his rebuttal testimony.

**Q. MS. JULIE M. CANNELL IS RECOMMENDING THAT THE COMMISSION AWARD A HIGHER THAN NORMAL EQUITY RETURN BECAUSE OF A PERCEPTION OF HIGHER INFLATION AND HIGHER INTEREST RATES. WOULD YOU PLEASE COMMENT?**

A. Yes. I would strongly recommend against this recommendation since the current data and forecasts do not support this claim.

**Q. DO YOU MEAN THAT INFLATION IS NOT EXPECTED TO INCREASE?**

A. That is correct. The Blue Chip Financial Forecasts actually expects inflation to decline from the historical levels of 3.5% in the first quarter of 2004 and 3.9% in the second quarter of 2004 down to a range of 2.2 to 2.5 percent over the next six quarters[2].

[2] Blue Chip Financial Forecasts, July 1, 2004.

**Q. BUT ISN'T THE ECONOMY GROWING TOO FAST?**

A. It did appear that the economy was growing too fast back in the third quarter of 2003 when the growth in Gross Domestic Product (GDP) was 7.4 percent, but that growth has fallen sharply since then, as shown in the following chart:

| | | |
|---|---|---|
| 3rd Qtr. | 2003 | 7.4% |
| 4th Qtr. | 2003 | 4.2% |
| 1st Qtr. | 2004 | 4.5% |
| 2nd Qtr. | 2004 | 3.0% |

Source: Blue Chip Financial Forecasts, August 1, 2004.

**Q. DOES IT APPEAR THAT WE MAY BE ENTERING A PERIOD OF STAGFLATION?**

A. Maybe, but not likely. The inflation of the last two quarters was mainly caused by a temporary disruption in the oil markets. At the same time the rise in oil prices has tempered GDP growth. The economic rule of thumb is that every penny per gallon that gasoline prices rise takes $1 billion out of the economy. The price of gasoline jumped by over 80 cents a gallon since the end of 2001, thereby offsetting more than ¼ of the $316 billion in stimulus that was provided by the three federal tax cuts[3].

[3] "Look Out Below", CBS MarketWatch.com, May 11, 2004.

**Q. WHAT OTHER DATA INDICATES THAT INFLATION IS NOT A PROBLEM?**

A. The economy still has a lot of excess capacity as indicated by the following statistics:

| | Current | Ten-Year Range |
|---|---|---|
| Total Industry Capacity Utilization | 77.8% | 74.8 – 83.6% |
| Unemployment Rate | 5.6% | 4.0 – 6.0% |

Source: Economic Indicators, June, 2004.

Inflationary pressures should not develop until the capacity utilization rate increases to the higher end of the ten-year range and the unemployment rate falls to the lower end of the ten-year range.

**Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?**

A. Yes.

OTS Exhibit No. 1-SR
Witness: Kevan L. Deardorff
Date: August 5, 2004
8/10/04 MBJ DX

DOCUMENT

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Exhibit to Accompany**

**the**

**Surrebuttal Testimony**

**of**

**Kevan L. Deardorff**

**Office of Trial Staff**



**Concerning:**

**Rate of Return**

OTS Exhibit No. 1-SR
Schedule No. 1
(Updated)

PPL Electric Utilities Corporation
OTS Recommended Weighted Cost of Capital
at December 31, 2004

| | | Capital Structure (1) | Cost Rates (2) | Weighted Cost of Capital (3=1x2) |
|---|---|---|---|---|
| (1) | Long-Term Debt | 51.30% | 6.43% | 3.30% |
| (2) | Preferred Stock | 1.83% | 6.19% | 0.11% |
| (3) | Common Equity | 46.87% | 9.00% | 4.22% |
| (4) | Total | 100.00% | | 7.63% |

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Six Electric Companies

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 7/23/04) | 4.93% | 4.13% | 9.06% |
| (2) | Spot Price (ending 7/23/04) | 4.91% | 4.13% | 9.04% |
| (3) | Average: | 4.92% | 4.13% | 9.05% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 4, 2004
Barron's, July 26, 2004

Expected Market Cost Rate of Equity
Using Data for the Barometer Group of Nine Electric Companies

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 7/23/04) | 4.73% | 4.03% | 8.76% |
| (2) | Spot Price (ending 7/23/04) | 4.73% | 4.03% | 8.76% |
| (3) | Average: | 4.73% | 4.03% | 8.76% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 4, 2004
Barron's June, July 26, 2004

Expected Market Cost Rate of Equity
Using Data for PPL Corporation

| | Time Period | Adjusted Dividend Yield(1) (1) | Growth Rate (2) | Expected Rate of Return (3=1+2) |
|---|---|---|---|---|
| (1) | 52 Week Average (ending 7/23/04) | 3.94% | 5.13% | 9.07% |
| (2) | Spot Price (ending 7/23/04) | 3.75% | 5.13% | 8.88% |
| (3) | Average: | 3.85% | 5.13% | 8.98% |

Notes: (1) Value Line's reported dividends are projected for the year ahead.

Sources: Value Line, Ratings and Reports, June 4, 2004
Barron's, July 26, 2004

## Expected Growth Rates
## for the Barometer Group of Electric Companies

| | Company | Value Line Dividend Growth (1) | Value Line Earnings Growth (2) | S & P Earnings Growth (3) | First Call Earnings Growth (4) | Smart Money Earnings Growth (5) |
|---|---|---|---|---|---|---|
| [1] | CH Energy Group | 0.0 | 0.5 | - | - | - |
| [2] | Central Vermont PS | 3.5 | 7.5 | - | - | - |
| [3] | Consolidated Edison | 1.0 | -1.5 | 3.0 | 2.5 | 2.8 |
| [4] | Duquesne Light Holdings | -4.0 | 11.0 | 4.0 | 4.0 | 5.0 |
| [5] | Energy East Corp. | 4.0 | 1.0 | 5.0 | 4.0 | 4.7 |
| [6] | Green Mountain Power | 12.5 | 3.5 | - | - | - |
| [7] | Northeast Utilities | 8.5 | 10.0 | 4.0 | 4.5 | 4.0 |
| [8] | NSTAR | 2.5 | 3.0 | 4.0 | 5.0 | 4.3 |
| [9] | Pepco Holdings | 16.0 | 3.5 | 4.0 | 3.0 | 2.7 |
| [10] | Nine Company Average | 4.9 | 4.3 | - | - | - |
| [11] | Six Company Average | 4.7 | 4.5 | 4.0 | 3.8 | 3.9 |
| [12] | PPL Corporation | 7.0 | 5.5 | 5.0 | 5.0 | 5.0 |

Sources: Value Line Investment Survey, June 4, 2004
Internet, Finance.yahoo.com and Smartmoney.com, July 26, 2004
Standard & Poor's Earnings Guide, July, 2004

PPL Electric Utilities Corporation
Interest Coverage

| | | Capital Structure (1) | Cost Rates (2) | Weighted Cost of Capital (3= 1x2) | Effective Tax Rate Complement(1) (4) | Pre-Tax Cost of Capital (5=3/4) |
|---|---|---|---|---|---|---|
| (1) | Debt | 51.30% | 6.43% | 3.30% | | 3.30% |
| (2) | Preferred Stock | 1.83% | 6.19% | 0.11% | 0.5851 | 0.19% |
| (3) | Common Equity | 46.87% | 9.00% | 4.22% | 0.5851 | 7.21% |
| (4) | Total | 100.00% | | 7.63% | | 10.70% |

(5) Pre-Tax Coverage: 10.70/3.30 = 3.24

(6) Notes: (1) Effective income tax rate assumed to be 41.493%.
[35% Fed. Inc. Tax + (9.99% State Inc. Tax x (1-.35)].

PPL Electric Utilities Corporation
Interest Coverage
Hypothetical

| | | Hypothetical Capital Structure (1) | Cost Rates (2) | Weighted Cost of Capital (3= 1x2) | Effective Tax Rate Complement(1) (4) | Pre-Tax Cost of Capital (5=3/4) |
|---|---|---|---|---|---|---|
| (1) | Debt | 46.25% | 6.43% | 2.97% | | 2.97% |
| (2) | Preferred Stock | 1.83% | 6.19% | 0.11% | 0.5851 | 0.19% |
| (3) | Common Equity | 51.92% | 9.00% | 4.67% | 0.5851 | 7.99% |
| (4) | Total | 100.00% | | 7.76% | | 11.15% |

(5) Pre-Tax Coverage: 11.15/2.97 = 3.75

(6) Notes: (1) Effective income tax rate assumed to be 41.493%.
[35% Fed. Inc. Tax + (9.99% State Inc. Tax x (1-.35)].

DOCUMENT

OTS Statement No. 3
Witness: Joseph Kubas
Date: June 29, 2004
8/10/04 Hbg FX

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Direct Testimony**

**of**

**Joseph Kubas**

**Office of Trial Staff**



**Concerning:**

**Present Rate Revenue**

**Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?**

A. My name is Joseph Kubas and my business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg PA 17105-3265.

**Q. IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am employed as a Fixed Utility Valuation Engineer with the Office of Trial Staff.

**Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?**

A. An outline of my education and employment experience is attached as Appendix A.

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

A. The purpose of my direct testimony is to propose an adjustment to the present rate revenue of the PPL Electric Utilities Corporation's (PPL or Company) request for $164,400,000 in additional annual distribution revenue, and $57,300,000 in additional transmission revenue, filed March 29, 2004.

**Q. WHAT IS A TEST YEAR AND WHAT TEST YEAR HAS THE COMPANY SELECTED IN THIS CASE?**

A. A test year is a twelve month period representative of a utility's expected level of rate base, revenue, and expenses. There are two types of test years. A historic test year is a twelve-month period selected by a utility that represents a recent full year

of actual data. A future test year normally represents a year of projected data ending one year after the end of the historic test year. In this case, the Company selected a future test year ending December 31, 2004. This future test year includes Company projected customer data, sales and revenue.

**Q. WHAT IS THE COMPANY'S CLAIM FOR PRESENT RATE REVENUE FOR THE TEST YEAR ENDING DECEMBER 31, 2004?**

A. The Company claims it will receive $523,208,000 in total present rate distribution revenues (See PPL Exhibit Future 1, Schedule D1, Column 6). This $523,208,000 is based on total electric sales of 36,805,036,000 Kilowatt Hours (kWh) (See PPL Exhibit Future 1, Schedule D3, Page 3, Column 4).

**Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COMPANY'S CLAIM FOR PRESENT RATE REVENUE?**

A. I am recommending that present rate revenue be increased by $15,109,000.

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

A. As a result of my analysis, I determined that the Company has not properly weather normalized load for residential heating customers.

## I. Weather Normalization

**Q. WHAT IS MEANT BY THE TERM "WEATHER NORMALIZATION"?**

A. This term describes a methodology used to restate historic test year actual sales on a per customer basis to the level of sales that the utility would have achieved had the actual heating or cooling degree-days been normal.

**Q. PLEASE EXPLAIN THE TERM "HEATING DEGREE-DAY".**

A. As defined by National Oceanic and Atmospheric Administration (NOAA), the term "heating degree-day" represents the variance from 65 degrees Fahrenheit of the mean temperature for the day. The mean temperature for any twenty-four hour period is the sum of the high temperature plus the low temperature divided by two. For example, if the high temperature for the day was 28 degrees and the low temperature was 2 degrees, the mean for that day was 15 degrees ((28+2) /2 = 15). When the 15 degree mean temperature for the day is compared to 65 degrees, the result is 50 heating degree-days (65 - 15 = 50).

**Q. PLEASE EXPLAIN THE TERM "NORMAL" AS IT RELATES TO HEATING DEGREE-DAYS.**

A. The term "normal", when used within a weather normalization calculation, refers to the level of heating or cooling degree-days to which actual heating or cooling degree-days, as occurring during the historic test period, will be compared. For

example, if 5,500 actual heating degree-days occurred in the historic test year and the normal level of heating degree-days is 6,000, the test year is considered to have been "warmer than normal" by 500 heating degree-days (6,000 - 5,500 = 500). That is to say, that, had the weather been "normal" from a heating degree standpoint, the utility would have realized a higher level of retail sales during the historic test year. The converse is also true; if the historic test year level of actual heating degree-days exceeds the "normal" level, then the utility's historic test year sales were higher than otherwise would have occurred because the temperature was "colder than normal".

**Q. HOW IS THE "NORMAL" LEVEL OF HEATING DEGREE-DAYS COMPILED?**

A. The data is complied by the NOAA and it defines "normal" levels of heating degree-days according to the following definition:

> Methodology: Normals have been defined as the arithmetic mean of a climatological element computed over a long time period. International agreements eventually led to the decision that the appropriate time period would be three consecutive decades. Climatography of the United States No. 81, Pennsylvania January 1992.

**Q. WHAT DATA IS REQUIRED TO CALCULATE WEATHER NORMALIZED SALES?**

A. To calculate weather normalized sales, the following data is required:

1. The number of customers by month for each month of the historic test year.
2. The actual sales to the customers in 1. above for the historic test year.
3. The base load of the customers in 1. above for the historic test year.
4. The actual monthly heating degree-days for each month of the historic year as recorded by NOAA.
5. The normal monthly heating degree-days for each month as compiled by NOAA.

**Q. PLEASE EXPLAIN WHAT IS MEANT BY BASE LOAD OF CUSTOMERS.**

A. The base load of customers is the monthly usage of each customer that is considered to be unaffected by a change in temperature for purposes of the weather normalization calculation. A customer's base load usage represents the amount of electricity used to operate appliances such as water heaters, clothes dryers, and ranges. Generally, the base load usage is the average usage per customers for the months in the historic test year during which zero or only a very few normal

heating degree-days occur. The base load usage is excluded for the weather normalization calculation because it is assumed to be non-weather sensitive.

**Q. WHY IS IT IMPORTANT TO DETERMINE THE BASE AND HEATING LOAD OF CUSTOMERS IN RATE CASES?**

A. By separating electric usage into base and heat load, the heat load can be normalized for variations in temperature.

## II. Forecasting Model

**Q. DESCRIBE HOW THE COMPANY DEVELOPED ITS PRESENT RATE REVENUE CLAIM OF $523,208,000.**

A. According to PPL witness David R. Woodruff, the Company used a Forecasting Model (Model) to project the number of customers and total usage for the test year ending December 31, 2004 (See PPL Statement No. 3, Page 4).

**Q. DID THE COMPANY PROVIDE A WORKING COPY OF THE MODEL WITH THE FORMULA INTACT?**

A. No.

**Q. DID YOU REQUEST A WORKING COPY OF THE MODEL?**

A. Yes, however, the Company refused to provide a working copy (See OTS Exhibit No. 3, Schedule 9).

**Q. WOULD IT HAVE BEEN USEFUL TO HAVE A WORKING COPY OF THE MODEL?**

A. Yes. With a working copy of the Model, the advocates could have made changes in the inputs and assumptions the Company used to project the number of customers and sales.

**Q. WHAT DOES THIS MODEL USE TO FORECAST CUSTOMERS AND SALES?**

A. According to PPL witness David R. Woodruff, the Model uses a regression analysis of historic data, economic data, and weather data to forecast the number of customers and usage. The Company forecasted weather using a 20 year average of the heating and cooling degree-days at the Lehigh Valley, Harrisburg, Wilkes-Barre/Scranton and Williamsport airports (See PPL Statement No. 3, Page 4).

**Q. ARE THE MODEL INPUTS THAT YOU ARE AWARE OF CORRECT?**

A. No. With the limited information that I have about the Model, I believe there are inputs and assumptions in the Model that are incorrect.

**Q. WHAT SPECIFIC INPUTS AND ASSUMPTIONS IN THE MODEL ARE INCORRECT?**

A. First, the weather data that the Company states it obtained from the four airports does not appear to be official NOAA data. Second, the Commission has a long-standing policy of using 30 years worth of data to determine "normal" weather and heating degree-days. There may be more inputs and assumptions that are incorrect, but without a working copy of the Model, I have no way of knowing what they are.

**Q. HOW DID YOU DETERMINE THAT THE WEATHER DATA THAT THE COMPANY USED IS NOT OFFICIAL NOAA DATA?**

A. I compared the heating degree-day that the Company used with the official Heating Degree-days (HDD) as determined and published by NOAA. For example, in December 2002, the Company claims that there were 1,077 HDDs at the Allentown Airport (See OTS Exhibit No. 3, Schedule 1, Page 2). The official NOAA HDD data shows 1,091 HDDs (See OTS Exhibit No. 3, Schedule 2, Page 2). Similar differences between Company data and NOAA data appear in almost every other month at the Lehigh Valley, Harrisburg, Wilkes-Barre/Scranton and Williamsport airports.

**Q. WHY IS IT PROPER TO USE 30 YEARS WORTH OF DATA TO DETERMINE NORMAL WEATHER?**

A. First, it is my opinion that 30 years encompasses a time period sufficient enough to "smooth" short term aberrations in weather patterns. Second, it is consistent with the long-standing 30-year normal that NOAA and the Commission accept for determining normalized HDDs.

**Q. WHAT NORMAL HEATING DEGREE-DAYS SHOULD THE COMPANY HAVE USED?**

A. The Company should have used the normal 30 year level of 5,832 HDDs as determined by NOAA to determine normal sales (See OTS Exhibit No. 3, Schedule 3, Page 1, Column G, Line 14).

## III. Average Use Per Residential Heating Customer

**Q. IS THE COMPANY'S RESIDENTIAL CLASS COMPRISED OF VARIOUS SUBGROUPS?**

A. Yes. The Company's Residential Class is comprised of the following subgroups or Rate Schedules: Residential Service (RS), Residential Service - Thermal Storage (RTS) and Residential Service - Time of Day (RTD). The budgeted number of customers and their projected usages are shown on PPL Exhibit Future 1, Schedule D3, Page 3 Lines 1-3.

**Q. DID THE COMPANY INCLUDE A SCHEDULE SHOWING THE NUMBER OF RESIDENTIAL HEATING CUSTOMERS AND THEIR CORRESPONDING USAGE IN THE FILING?**

A. No.

**Q. DID YOU ASK THE COMPANY TO PROVIDE INFORMATION ON HEATING AND NON-HEATING CUSTOMERS?**

A. Yes. The Company provided a response to OTS-RE-8, which shows the actual number of heating and non-heating residential customers and their corresponding usage. This data indicates that over the past three years, residential heating customers made up 31.2% of all residential customers and non-heating customers made up the remaining 68.8% (See OTS Exhibit No. 3, Schedule 4, Page 2, Line 39). The response also indicated that over the past three years, sales to heating customers comprised 47.3% of all sales to residential customers, and sales to non-heating customers comprised the remaining 52.7% (See OTS Exhibit No. 3, Schedule 4, Page 3, Line 39).

**Q. USING THE 31.2 PERCENT DESCRIBED ABOVE, WERE YOU ABLE TO DETERMINE THE BUDGETED NUMBER OF RESIDENTIAL HEATING BILLS?**

A. Yes. As shown on OTS Exhibit No. 3, Schedule 5, Page 1 of 3, Column E, Line 24, I determined that the Company has projected 4,366,477 monthly bills.

**Q. USING THE 47.3 PERCENT DESCRIBED ABOVE, WERE YOU ABLE TO DETERMINE THE BUDGETED USAGE OF RESIDENTIAL HEATING CUSTOMERS?**

A. Yes. As shown on OTS Exhibit No. 3, Schedule 5, Page 3 of 3, Column D, Line 9, I determined that the Company is projecting that the residential heating customers will use 6,290,844,186 kWh.

**Q. WHAT AVERAGE USAGE PER RESIDENTIAL HEATING CUSTOMER IS THE COMPANY FORECASTING?**

A. Dividing the 6,290,844,186 kWh by the 4,366,447 bills described above, I determined that the Company is forecasting that the average heating customer will use 1,441 kWh per month (See OTS Exhibit No. 3, Schedule 8, Column B, Lines 1-3).

**Q. DO YOU AGREE WITH THE COMPANY'S PROJECTED 1,441 KWH PER MONTH AVERAGE USAGE FOR RESIDENTIAL HEATING CUSTOMERS?**

A. No.

**Q. WHAT AVERAGE USE PER RESIDENTIAL HEATING CUSTOMER DO YOU RECOMMEND?**

A. I recommend that the average usage per residential heating customer be increased by 229 kWh to 1,670 kWh per month (1,670 kWh - 1,441 kWh = 229 kWh) (See OTS Exhibit No. 3, Schedule 8, Line 2).

**Q. HOW DID YOU DETERMINE THE 1,670 KWH PER MONTH?**

A. I determined the base load for the average residential heating customer and added this base load to the normalized weather load to determine the total load of 1,670 kWh per month.

**Q. HAVE YOU INCLUDED A WEATHER NORMALIZATION CALCULATION THAT PROPERLY PRESENTS THE BASE LOAD, HEAT LOAD, DEGREE-DAY DATA, AND TOTAL AVERAGE USAGE FOR RESIDENTIAL HEATING CUSTOMERS?**

A. Yes. I have included the OTS recommended base load and weather normalization calculation for residential heating customers (See OTS Exhibit No. 3, Schedule 7).

**Q. HOW DID YOU DETERMINE THE BASE LOAD OF A RESIDENTIAL HEATING CUSTOMER ON OTS EXHIBIT NO. 3, SCHEDULE 7?**

A. I reviewed the actual sales volumes for the residential heating customers from June 2000 through May 2003. This data shows that the least amount of electricity was used in October each year. Dividing monthly sales for October 2003 by the number of customers that month, I determined that the average base load for each residential heating customer is 949 kWh per month as shown on OTS Exhibit No. 3, Schedule 7, Column E, Line 22 (337,632,216 kWh divided by 355,644 customers = 949 kWh per customer).

**Q. HOW DID YOU DETERMINE THE HEAT SENSITIVE LOAD OF A RESIDENTIAL HEATING CUSTOMER ON OTS EXHIBIT NO. 3, SCHEDULE 7?**

A. As shown on OTS Exhibit No. 3, Schedule 7, the difference between actual monthly load and base load is the heat sensitive load for customers, which is shown under **Column E.** The actual heating degree-days under **Column F** are the average HDDs as reported by NOAA for this period. The heating sensitive load under **Column G** is the heating sensitive load of heating customers divided by the actual heating degree-days. The normal heating degree-days under **Column H** is the 30-year normal HDDs reported by NOAA (See OTS Exhibit No. 3, Schedule 3, Page 1). The normalized heating sensitive load under **Column I** is the heating sensitive load times the normal number of heating degree-days each month. The normalized load under **Column J** is the base load under **Column D** plus the normalized heating sensitive load under Column I, except for the months of June, July, August, September and October, which are the actual load under Column C.

**Q. WHAT IS THE TOTAL AVERAGE SALES FOR EACH RESIDENTIAL HEATING CUSTOMER?**

A. Dividing the total normalized usage of 7,132,142,893 kWh shown on OTS Exhibit No. 3, Schedule 7, Column J, Line 14 by the average 355,903 customers shown under Column B, Line 16, results in an average normalized monthly usage for a

Residential Heating customer of **1,670 kWh** per month (See OTS Exhibit No. 3, Schedule 7, Column D, Line 18).

**Q. HOW DOES THIS 1,670 KWH COMPARE TO WHAT THE COMPANY CLAIMED?**

A. As described above, the difference between the two amounts is 229 kWh, (1,670 kWh - 1,441 kWh = 229 kWh) (See OTS Exhibit No. 3, Schedule 8, Line 2).

**Q. BASED ON YOUR PROPOSED NORMALIZED USAGE OF 1,670 KWH PER MONTH, WHAT WOULD BE THE TOTAL KWH SALES FOR THE RESIDENTIAL HEATING RATE SCHEDULE?**

A. Multiplying the 4,366,447 residential heating bills described above by the 1,670 kWh per month = 7,291,778,000 kWh (See OTS Exhibit No. 3, Schedule 8, Column D, Lines 1-3). This is an increase of 1,000,934,000 kWh over the 6,290,844,000 kWh in sales that the Company is forecasting for the residential heating rate schedule (See OTS Exhibit No. 3, Schedule 8, Column C, Line 3).

## IV. Present Rate Revenue Adjustment

**Q. BASED ON YOUR RECOMMENDED SALES OF 7,291,778,000 KWH FOR RESIDENTIAL HEATING RATE SCHEDULE, WHAT WOULD BE THE INCREASE IN PRESENT RATE REVENUE?**

A. Based on my revised sales of 7,291,778,000 kWh, present rate revenue for the residential heating rate schedule should be increased by $15,109,000 (See OTS Exhibit No. 3, Schedule 8, Column C, Line 8).

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

A. Yes, it does.

Appendix "A"

**JOSEPH KUBAS**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**
**PO BOX 3265**
**HARRISBURG, PA 17105-3265**

**Education:** Bachelor of Science in Civil Engineering Technology, 1985, University of Pittsburgh at Johnstown, Johnstown, PA.

**Continuing Education:** Legal Principles and Practices of Surveying at the University of Maryland. Economics, Accounting, Lotus, at the Howard Community College. Accounting at the University of Pittsburgh at Johnstown. Managing Multiple Priorities at the Pennsylvania State University. Various PA-PUC and Utility Company Seminars.

**Professional Exams:** Engineer In Training, 1985,
Uniform Certified Public Accounting Exam, 1993.

**Experience:** **FIXED UTILITY VALUATION ENGINEER III**
December 1999 - Present

Pennsylvania Public Utility Commission
Office of Trial Staff

**Duties:** Perform the duties of a Fixed Utility Valuation Engineer III in the Office of Trial Staff (OTS).

Analyze and review valuation engineering, and rate structure data submitted by Water, Sewer, Telephone, Gas and Steam Heat utilities to justify utility service rates or alternative forms of regulation, by researching, analyzing, and reviewing rate case filings and investigations. Participate in on-site inspections of utility properties to determine the used and usefulness of the plant-in service and make recommendations. Prepare interrogatories in the areas of rate base, rate structure, revenue and quality of service in order to obtain additional information regarding a utility's filing. Analyze present and

proposed revenue and rate structure, and make recommendations regarding the appropriate methodology for each particular utility to employ. Prepare testimony and exhibits for the purpose of establishing the OTS positions in formal and informal proceedings before the Commission. Participate in Commission consultative report proceedings and collaboratives undertaken by the Commission.

**Experience:** **FIXED UTILITY VALUATION ENGINEER II**
April 1996 - December 1999

Pennsylvania Public Utility Commission
Office of Trial Staff and Bureau of Fixed Utility Services

**Duties:** Perform the duties of a Fixed Utility Valuation Engineer II in the Office of Trail Staff (OTS) and Bureau of Fixed Utility Services.

**Experience:** **FIXED UTILITY VALUATION ENGINEER TRAINEE, I & II**
May 1993 - March 1996

Pennsylvania Public Utility Commission
Office of Trial Staff
Telecommunications and Water Division

**Duties:** Perform the duties of a Fixed Utility Valuation Engineer II in the Rate Structure/Engineering Section of the Telecommunications and Water Division of the Office of Trial Staff (OTS).

**Experience:** **CIVIL ENGINEER**
May 1985 - January 1991

Clark Finefrock & Sackett Inc.
7135 Minstrel Way
Columbia, MD 21045

**Duties:** Engineering, Surveying, Computer, and Field Inspection work related to land development projects in Maryland.

## Testimony Before the Pennsylvania Public Utility Commission

| | | | |
|---|---|---|---|
| 1. | National Utilities Inc. (Water) | R-00953416 | April 1996 |
| 2. | Consumer Pennsylvania Water Company - Roaring Creek Division | R-00973869 | May 1997 |
| 3. | Philadelphia Suburban Water Company | R-00973952 | August 1997 |
| 4. | Bell Atlantic - Pennsylvania Inc. | P-00971307 | March 1998 |
| 5. | City of Bethlehem- Bureau of Water | R-00984375 | September 1998 |
| 6. | Pennsylvania Telephone Association - Chapter 30 Plan | P-00981425 | December 1998 |
| 7. | GTE North Inc. Telephone Chapter 30 Plan | P-00981449 | February 1999 |
| 8. | Pennsylvania American Water Co. | R-00994638 | August 1999 |
| 9. | Philadelphia Suburban Water Co. | R-00994868 | February 2000 |
| 10. | PG Energy (Gas) | R-00005119 | June 2000 |
| 11. | Pennsylvania American Water - Coatesville Acquisition | A-212285-F07201 | July 2000 |
| 12. | T. W Phillips Gas and Oil Company | R-00005459 | October 2000 |
| 13. | Verizon North - Chapter 30 Plan | P-00001854 | January 2001 |
| 14. | Philadelphia Gas Works | R-00006042 | April 2001 |
| 15. | PFG Gas Inc. & Penn Fuels Gas Co. | R-00013679 | July 2001 |
| 16. | Pennsylvania American Water Co. | R-00016339 | August 2001 |
| 17. | Philadelphia Suburban Water Co. | R-00016750 | February 2002 |
| 18. | Philadelphia Gas Works | R-00017034 | May 2002 |
| 19. | PFG Gas Inc. & Penn Fuels Gas Co | R-00027389 | July 2002 |
| 20. | Verizon - Pennsylvania, Inc. | P-00021973 | September 2002 |
| 21. | Verizon - Pennsylvania, Inc. | P-00937105-F0002 | January 2003 |
| 22. | Pennsylvania American Water Co. | R-00027982 | April 2003 |
| 23. | Dominion Peoples 1307(f) | R-00038170 | May 2003 |
| 24. | Verizon PA / Verizon North | C-20027195 | July 2003 |
| 25. | National Fuel Gas Distribution, Inc. | R-00038168 | July 2003 |
| 26. | Aqua Pennsylvania Inc. | R-00038805 | Feb 2004 |
| 27. | Dominion Peoples 1307(f) | R-00049153 | May 2004 |

OTS Exhibit No. 3
Witness: Joseph Kubas
Date: June 29, 2004
8/10/04 Hbg DK

DOCUMENT

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**v.**

**PPL ELECTRIC UTILITIES CORPORATION**

**Docket No. R-00049255**



**Exhibit to Accompany**

**the**

**Direct Testimony**

**of**

**Joseph Kubas**

**Office of Trial Staff**



**Concerning:**

**Present Rate Revenue**

D. R. Woodruff
Revised

**PPL Electric Utilities Corporation**
**Response to Interrogatories of the Office of Trial Staff, Set 1,**
**Dated March 31, 2004**
**Docket No. R-00049255**

Q.OTS-RE-5. Provide a schedule that shows the actual and normal heating and cooling degree days by month and location that were used in the 20 year normalization period described on page 4 of PPL Statement No. 3.

A.OTS.RE-5. See Attachment 1.

PPL Electric Utilities Corporation
Calendar Month Heating and Cooling Degree Days
Allentown-Bethlehem-Easton (ABE) Airport

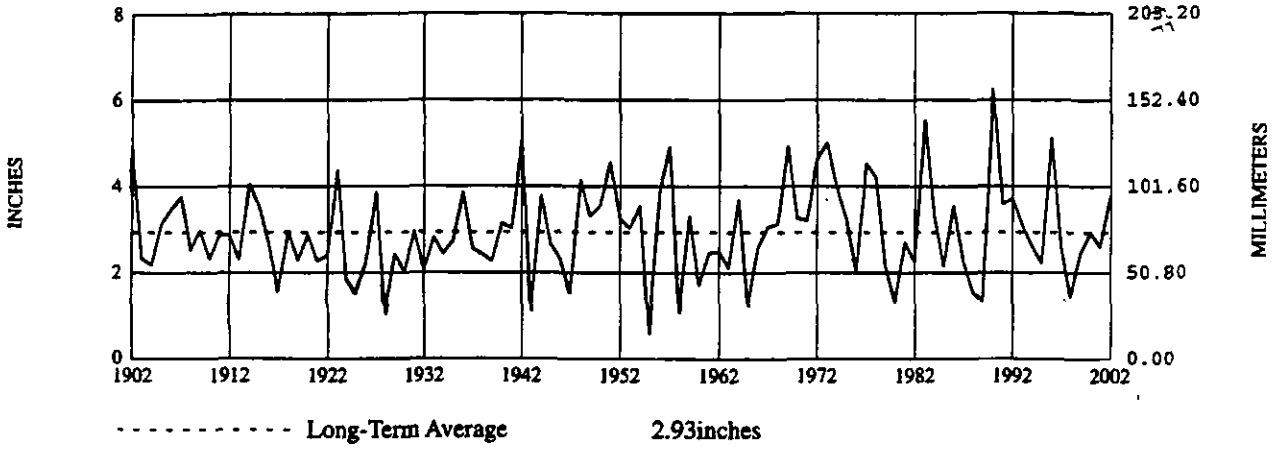
| Year | Month | HDD | CDD |
|---|---|---|---|
| 2001 | 4 | 429 | 11 |
| 2001 | 5 | 159 | 35 |
| 2001 | 6 | 29 | 167 |
| 2001 | 7 | 17 | 142 |
| 2001 | 8 | 0 | 274 |
| 2001 | 9 | 111 | 49 |
| 2001 | 10 | 344 | 3 |
| 2001 | 11 | 525 | 0 |
| 2001 | 12 | 810 | 0 |
| 2002 | 1 | 940 | 0 |
| 2002 | 2 | 802 | 0 |
| 2002 | 3 | 743 | 0 |
| 2002 | 4 | 411 | 39 |
| 2002 | 5 | 256 | 32 |
| 2002 | 6 | 19 | 164 |
| 2002 | 7 | 0 | 334 |
| 2002 | 8 | 4 | 316 |
| 2002 | 9 | 41 | 92 |
| 2002 | 10 | 415 | 18 |
| 2002 | 11 | 714 | 0 |
| December 2002 ▶ 2002 | 12 | 1077 | 0 |
| 2003 | 1 | 1276 | 0 |
| 2003 | 2 | 1086 | 0 |
| 2003 | 3 | 770 | 0 |
| 2003 | 4 | 481 | 1 |
| 2003 | 5 | 231 | 5 |
| 2003 | 6 | 58 | 133 |
| 2003 | 7 | 0 | 292 |
| 2003 | 8 | 0 | 308 |
| 2003 | 9 | 40 | 64 |
| 2003 | 10 | 406 | 0 |
| 2003 | 11 | 542 | 1 |
| 2003 | 12 | 984 | 0 |
| 2004 | 1 | 1326 | 0 |
| 2004 | 2 | 985 | 0 |

# CLIMATOLOGICAL DATA

## PENNSYLVANIA

### DECEMBER 2002

VOLUME 107 NUMBER 12
ISSN 0364-5843




PENNSYLVANIA PRECIPITATION DECEMBER, 1902-2002

### TEMPERATURE AND PRECIPITATION EXTREMES

| | | | |
|---|---|---|---|
| HIGHEST TEMPERATURE | 64 | DECEMBER 20 | WAYNESBURG 1 E |
| LOWEST TEMPERATURE | -12 | DECEMBER 9 | BRADFORD REGIONAL AP R |
| GREATEST TOTAL PRECIPITATION | 6.91 | | COATESVILLE 2 W |
| LEAST TOTAL PRECIPITATION | 1.94 | | MCKEESPORT |
| GREATEST 1 DAY PRECIPITATION | 2.23 | DECEMBER 12 | LEHIGHTON 1 SSW |
| GREATEST TOTAL SNOWFALL | 37.3 | | SPRING CREEK 5 NE |
| GREATEST DEPTH OF SNOW OR ICE | 24 | DECEMBER 30 | PLEASANT MOUNT 1 W |

"I certify that this is an official publication of the National Oceanic and Atmospheric Administration (NOAA). It is compiled using information from weather observing sites supervised by NOAA/National Weather Service and received at the National Climatic Data Center (NCDC), Asheville, North Carolina 28801."

Thomas R Karl

DIRECTOR
NATIONAL CLIMATIC DATA CENTER

noaa

National Oceanic and

National Environmental Satellite, Data

National Climatic Data Center

PENNSYLVANIA
DECEMBER 2002

# MONTHLY STATION AND DIVISION SUMMARY

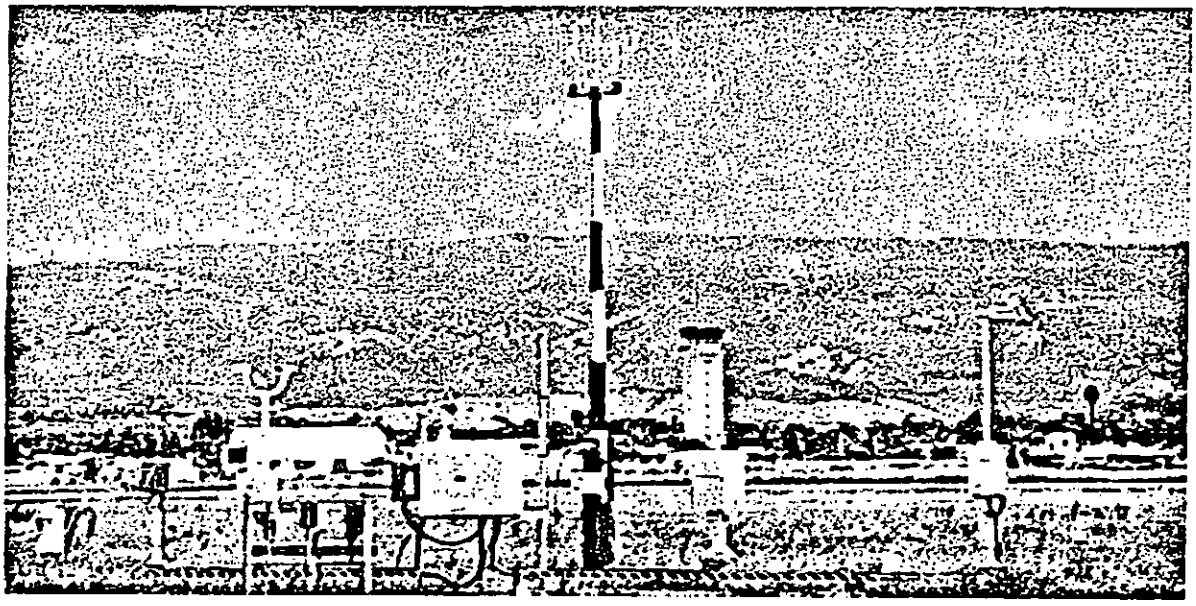
| STATION | TEMPERATURE (°F) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | AVERAGE MAXIMUM | AVERAGE MINIMUM | AVERAGE | DEPARTURE FROM NORMAL | HIGHEST | DATE | LOWEST | DATE | HEATING DEGREE DAYS | COOLING DEGREE DAYS | NO. OF DAYS MAX 90 OR ABOVE | NO. OF DAYS MAX 32 OR BELOW | NO. OF DAYS MIN 32 OR BELOW | NO. OF DAYS MIN 0 OR BELOW |
| PENNSYLVANIA | | | | | | | | | | | | | | |
| POCONO MOUNTAINS 01 | | | | | | | | | | | | | | |
| FRANCIS E WALTER DAM | M | M | M | | 54 | 23 | 0 | 4 | | | 0 | 10 | 21 | 1 |
| HAWLEY 1 E | 34.5 | 16.7 | 25.6 | -2.9 | 50 | 21 | -3 | 10 | 1215 | 0 | 0 | 11 | 30 | 2 |
| MATAMORAS | 36.1 | 19.4 | 27.8 | -2.5 | 50 | 21 | 3 | 7 | 1147 | 0 | 0 | 6 | 30 | 0 |
| PLEASANT MOUNT 1 W | 31.1 | 15.8 | 23.5 | -.7 | 50 | 21 | -6 | 9 | 1282 | 0 | 0 | 18 | 31 | 4 |
| STROUDSBURG | 37.2 | 20.8 | 29.0 | -1.9 | 56 | 21 | 3 | 7 | 1107 | 0 | 0 | 6 | 30 | 0 |
| TOBYHANNA POCONO MTN A | M | M | M | | 45 | 2 | -1 | 18 | | | 0 | 7 | 15 | 1 |
| WILKES BARRE SCRANTON | 35.1 | 22.9 | 29.0 | -2.4 | 56 | 20 | 5 | 9+ | 1110 | 0 | 0 | 10 | 25 | 0 |
| --DIVISIONAL DATA-------> | | | 27.0 | -.7 | | | | | | | | | | |
| EAST CENTRAL MOUNTAINS 02 | | | | | | | | | | | | | | |
| ALLENTOWN WSO AIRPORT //R | 37.5 | 21.7 | 29.6 | -2.4 | 59 | 20 | 5 | 10+ | 1091 | 0 | 0 | 6 | 26 | 0 |
| BELTZVILLE DAM | M | M | M | | 56 | 23 | 4 | 9 | | | 0 | 5 | 19 | 0 |
| RODALE RESEARCH CENTER | 37.1 | 20.9 | 29.0 | -1.7 | 57 | 21+ | 3 | 7 | 1111 | 0 | 0 | 8 | 28 | 0 |
| --DIVISIONAL DATA-------> | | | 29.3 | -1.4 | | | | | | | | | | |
| SOUTHEASTERN PIEDMONT 03 | | | | | | | | | | | | | | |
| BLUE MARSH LAKE | M | M | M | | 57 | 20 | 4 | 10 | | | 0 | 5 | 15 | 0 |
| BUCKSVILLE | 40.0 | 20.4 | 30.2 | -3.0 | 59 | 21 | 1 | 10 | 1072 | 0 | 0 | 4 | 28 | 0 |
| COATESVILLE 2 W | 38.6 | 22.7 | 30.7 | -2.9 | 60 | 20 | 6 | 7 | 1058 | 0 | 0 | 4 | 28 | 0 |
| DEHART DAM | 39.3 | 21.2 | 30.3 | | 53 | 21 | 5 | 8+ | 1069 | 0 | 0 | 4 | 27 | 0 |
| GRATERFORD 1 E | 41.1 | 22.9 | 32.0 | -1.2 | 60 | 21 | 0 | 7 | 1015 | 0 | 0 | 4 | 26 | 1 |
| HAMBURG | 38.4 | 22.0 | 30.2 | -1.9 | 58 | 21 | 4 | 7 | 1073 | 0 | 0 | 4 | 29 | 0 |
| HARRISBURG 1 NE | 37.9 | 23.1 | 30.5 | | 53 | 21+ | 10 | 8+ | 1063 | 0 | 0 | 8 | 28 | 0 |
| LANCASTER 2 NE FILT PL | 38.9 | 23.1 | 31.0 | -3.1 | 58 | 20 | 2 | 7 | 1048 | 0 | 0 | 5 | 27 | 0 |
| LANDISVILLE 2 NW | 39.9 | 21.1 | 30.5 | -3.4 | 58 | 20 | -6 | 7 | 1062 | 0 | 0 | 5 | 26 | 1 |
| LEBANON 2 W | 37.4 | 20.8 | 29.1 | -3.1 | 56 | 20 | 1 | 7 | 1107 | 0 | 0 | 6 | 28 | 0 |
| MARCUS HOOK | 42.9 | 32.2 | 37.6 | -.8 | 59 | 21+ | 14 | 7 | 844 | 0 | 0 | 2 | 15 | 0 |
| MIDDLETOWN HARRISBURG R | 37.9 | 24.1 | 31.0 | | 55 | 20 | 9 | 7 | 1047 | 0 | 0 | 7 | 25 | 0 |
| NESHAMINY FALLS | M | M | M | | | | | | | | | | | |
| NEW HOLLAND 2 SE | 38.6 | 24.3 | 31.5 | | 58 | 20 | 5 | 7 | 1031 | 0 | 0 | 5 | 25 | 0 |
| NORRISTOWN | 42.1 | 25.0 | 33.6 | -1.8 | 60 | 21 | 10 | 9 | 974 | 0 | 0 | 5 | 27 | 0 |
| OCTORARO LAKE | 39.9 | 20.8 | 30.4 | -3.9 | 60 | 20 | -2 | 7 | 1065 | 0 | 0 | 4 | 29 | 1 |
| PHILADELPHIA FRNKLIN I | 43.6 | 32.6 | 38.1 | | 61 | 20 | 15 | 7 | 827 | 0 | 0 | 1 | 14 | 0 |
| PHILADELPHIA WSCMO AP R | 42.2 | 28.5 | 35.4 | -2.0 | 59 | 20 | 16 | 7 | 910 | 0 | 0 | 3 | 22 | 0 |
| PHOENIXVILLE 1 E | 41.4 | 22.1 | 31.8 | -3.1 | 60 | 20 | 4 | 7 | 1024 | 0 | 0 | 2 | 28 | 0 |
| READING 4 NNW | 39.2 | 24.5 | 31.9 | -2.4 | 60 | 21+ | 8 | 10 | 1019 | 0 | 0 | 6 | 26 | 0 |
| SAFE HARBOR DAM | 39.5 | 26.1 | 32.8 | | 57 | 21 | 15 | 7 | 992 | 0 | 0 | 6 | 26 | 0 |
| SELLERSVILLE | 39.1 | 21.2 | 30.2 | | 59 | 21 | 2 | 7 | 1072 | 0 | 0 | 5 | 29 | 0 |
| SPRINGTOWN 1 NNE | 39.5 | 22.9 | 31.2 | | 57 | 21 | 10 | 9 | 1042 | 0 | 0 | 5 | 29 | 0 |
| WEST CHESTER 2 NW | 40.6 | 20.3 | 30.5 | -4.4 | 60 | 21 | -2 | 7 | 1066 | 0 | 0 | 5 | 29 | 1 |
| --DIVISIONAL DATA-------> | | | 31.8 | -2.1 | | | | | | | | | | |
| LOWER SUSQUEHANNA 04 | | | | | | | | | | | | | | |
| BIGLERVILLE | 38.4 | 22.7 | 30.6 | -1.3 | 54 | 21 | 7 | 7 | 1062 | 0 | 0 | 6 | 26 | 0 |
| BLOSERVILLE 1 N | 37.2 | 23.7 | 30.5 | -1.8 | 52 | 21 | 10 | 9+ | 1064 | 0 | 0 | 9 | 25 | 0 |
| CHAMBERSBURG 1 ESE | 38.1 | 23.8 | 31.0 | -2.2 | 52 | 21+ | 10 | 7 | 1048 | 0 | 0 | 8 | 25 | 0 |
| EISENHOWER NATL HIST S | 39.8 | 22.1 | 31.0 | -3.7 | 55 | 23 | 0 | 7 | 1048 | 0 | 0 | 5 | 26 | 1 |
| HANOVER 4 SW | 38.8 | 20.7 | 29.8 | | 55 | 20 | -1 | 7 | 1086 | 0 | 0 | 6 | 28 | 1 |
| SHIPPENSBURG R | 38.4 | 24.4 | 31.4 | -2.0 | 54 | 20 | 10 | 7 | 1034 | 0 | 0 | 5 | 25 | 0 |
| YORK 3 SSW PUMP STN | 42.3 | 23.4 | 32.9 | -1.6 | 55 | 22+ | 0 | 7 | 993 | 0 | 0 | 2 | 26 | 1 |
| --DIVISIONAL DATA-------> | | | 31.0 | -2.0 | | | | | | | | | | |
| MIDDLE SUSQUEHANNA 05 | | | | | | | | | | | | | | |
| BENTON 3 NE | 34.3 | 17.2 | 25.8 | | 52 | 21 | -2 | 9 | 1206 | 0 | 0 | 11 | 29 | 2 |
| LAURELTON CENTER | 38.0 | 21.7 | 29.9 | -1.7 | 52 | 22 | 5 | 7 | 1082 | 0 | 0 | 3 | 29 | 0 |
| LEWISBURG | 35.9 | 19.4 | 27.7 | | 51 | 21 | 1 | 7 | 1149 | 0 | 0 | 9 | 29 | 0 |
| LEWISTOWN | 38.5 | 21.9 | 30.2 | -2.1 | 53 | 20 | 3 | 9 | 1071 | 0 | 0 | 5 | 27 | 0 |
| SELINSGROVE 2 S | 36.4 | 20.9 | 28.7 | -2.8 | 53 | 21+ | 7 | 7 | 1119 | 0 | 0 | 10 | 26 | 0 |
| WILLIAMSPORT LYCOMING R | 35.4 | 21.2 | 28.3 | -2.4 | 54 | 20 | 3 | 9 | 1130 | 0 | 0 | 11 | 27 | 0 |
| WILLIAMSPORT 2 | 36.0 | 21.5 | 28.8 | | 54 | 20 | 6 | 9+ | 1116 | 0 | 0 | 8 | 29 | 0 |
| --DIVISIONAL DATA-------> | | | 28.5 | -2.0 | | | | | | | | | | |
| UPPER SUSQUEHANNA 06 | | | | | | | | | | | | | | |
| CANTON | 34.1 | 15.9 | 25.0 | -3.1 | 49 | 21 | -3 | 10+ | 1232 | 0 | 0 | 14 | 31 | 3 |
| COWANESQUE DAM | 33.3 | 17.4 | 25.4 | | 46 | 21 | 1 | 19+ | 1222 | 0 | 0 | 13 | 30 | 0 |
| LAPORTE | 31.2 | 17.6 | 24.4 | | 50 | 21 | 2 | 10+ | 1250 | 0 | 0 | 15 | 31 | 0 |
| MONTROSE | 32.3 | 15.3 | 23.8 | -3.0 | 49 | 21 | -7 | 9 | 1268 | 0 | 0 | 16 | 31 | 2 |
| TOWANDA 1 ESE | 34.6M | 17.4M | 26.0M | -4.2 | 54 | 21 | 3 | 10+ | 1200 | 0 | 0 | 10 | 20 | 0 |
| WELLSBORO 4 SW | 31.0 | 16.5 | 23.8 | -3.0 | 46 | 21 | 0 | 10+ | 1271 | 0 | 0 | 17 | 31 | 2 |
| --DIVISIONAL DATA-------> | | | 24.7 | -2.3 | | | | | | | | | | |
| CENTRAL MOUNTAINS 07 | | | | | | | | | | | | | | |

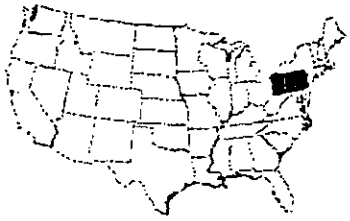
**PPL Electric Utilities Corporation**
**Summary NOAA Heating Degree Days 1971 - 2000**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| 1 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 2 | January | 1,159 | 1,076 | 1,214 | 1,211 | 4,660 | 1,165 |
| 3 | February | 967 | 901 | 1,027 | 1,014 | 3,909 | 977 |
| 4 | March | 797 | 723 | 857 | 824 | 3,201 | 800 |
| 5 | April | 470 | 390 | 510 | 471 | 1,841 | 460 |
| 6 | May | 197 | 148 | 219 | 196 | 760 | 190 |
| 7 | June | 34 | 14 | 53 | 38 | 139 | 35 |
| 8 | July | 15 | 0 | 9 | 6 | 30 | 8 |
| 9 | August | 8 | 1 | 18 | 12 | 39 | 10 |
| 10 | September | 106 | 52 | 138 | 116 | 412 | 103 |
| 11 | October | 392 | 338 | 431 | 417 | 1,578 | 395 |
| 12 | November | 675 | 621 | 711 | 710 | 2,717 | 679 |
| 13 | December | 1,010 | 937 | 1,047 | 1,048 | 4,042 | 1,011 |
| 14 | Totals | 5,830 | 5,201 | 6,234 | 6,063 | 23,328 | 5,832 |

CLIMATOGRAPHY OF THE UNITED STATES NO. 81

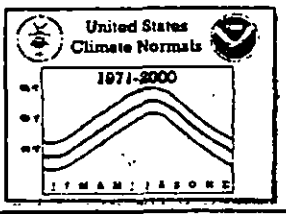
# Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000





# 36 PENNSYLVANIA

NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
NATIONAL ENVIRONMENTAL SATELLITE, DATA, AND INFORMATION SERVICE
NATIONAL CLIMATIC DATA CENTER
ASHEVILLE, NC



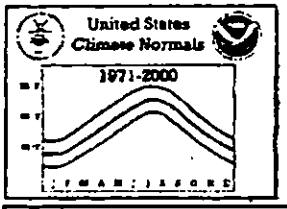

# CLIMATOGRAPHY OF THE UNITED STATES NO. 81

Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days
1971-2000

## PENNSYLVANIA



| No. | Station Name | Element | DEGREE DAYS (Total) JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 002 | ALLENTOWN LEHIGH VLY AP | HDD* | 1159 | 967 | 797 | 470 | 197 | 34 | 15 | 8 | 106 | 392 | 675 | 1010 | 5830 |
| | | CDD* | 0 | 0 | 1 | 6 | 45 | 153 | 288 | 216 | 73 | 5 | 0 | 0 | 787 |
| 003 | ALTOONA BLAIR CO AP | HDD | 1167 | 983 | 822 | 475 | 214 | 39 | 6 | 18 | 108 | 410 | 689 | 1021 | 5952 |
| | | CDD | 0 | 0 | 0 | 0 | 36 | 118 | 211 | 174 | 44 | 9 | 0 | 0 | 592 |
| 004 | ALTOONA 3 N | HDD | 1193 | 1006 | 852 | 484 | 220 | 43 | 7 | 15 | 95 | 409 | 690 | 1041 | 6055 |
| | | CDD | 0 | 0 | 0 | 0 | 34 | 108 | 196 | 163 | 41 | 4 | 0 | 0 | 546 |
| 005 | BAKERSTOWN 3 WNW | HDD | 1191 | 991 | 812 | 484 | 233 | 47 | 11 | 19 | 98 | 404 | 701 | 1031 | 6022 |
| | | CDD | 0 | 0 | 0 | 0 | 37 | 110 | 213 | 176 | 52 | 6 | 0 | 0 | 594 |
| 011 | BELTZVILLE DAM | HDD | 1266 | 1076 | 896 | 543 | 241 | 57 | 8 | 16 | 132 | 473 | 764 | 1093 | 6565 |
| | | CDD | 0 | 0 | 0 | 0 | 15 | 80 | 188 | 146 | 22 | 3 | 0 | 0 | 454 |
| 012 | BIGLERVILLE | HDD | 1184 | 997 | 833 | 493 | 209 | 37 | 6 | 9 | 97 | 420 | 702 | 1026 | 6013 |
| | | CDD | 0 | 0 | 0 | 0 | 36 | 133 | 255 | 203 | 51 | 6 | 0 | 0 | 684 |
| 013 | BLOSERVILLE 1 W | HDD | 1167 | 971 | 806 | 465 | 210 | 44 | 9 | 13 | 96 | 404 | 683 | 1016 | 5884 |
| | | CDD | 0 | 0 | 0 | 1 | 38 | 129 | 248 | 198 | 49 | 4 | 0 | 0 | 667 |
| 014 | BLUE MARSH LAKE | HDD | 1175 | 993 | 816 | 474 | 191 | 23 | 3 | 9 | 80 | 402 | 688 | 1022 | 5876 |
| | | CDD | 0 | 0 | 0 | 0 | 35 | 136 | 269 | 223 | 54 | 6 | 0 | 0 | 723 |
| 017 | BRADFORD RGNL AP | HDD | 1367 | 1168 | 1012 | 647 | 362 | 125 | 56 | 88 | 231 | 559 | 849 | 1202 | 7666 |
| | | CDD | 0 | 0 | 0 | 0 | 13 | 32 | 89 | 77 | 6 | 0 | 0 | 0 | 217 |
| 019 | BRADFORD 4 SW RES 5 | HDD | 1388 | 1195 | 1025 | 655 | 347 | 97 | 38 | 60 | 207 | 537 | 835 | 1200 | 7584 |
| | | CDD | 0 | 0 | 0 | 0 | 19 | 31 | 94 | 69 | 6 | 0 | 0 | 0 | 219 |
| 020 | BROOKVILLE SEWAGE PLT | HDD | 1292 | 1121 | 953 | 618 | 316 | 88 | 20 | 46 | 182 | 512 | 802 | 1118 | 7068 |
| | | CDD | 0 | 0 | 0 | 0 | 15 | 47 | 108 | 96 | 11 | 0 | 0 | 0 | 277 |
| 022 | BUCKSVILLE | HDD | 1129 | 950 | 791 | 448 | 179 | 22 | 0 | 6 | 72 | 368 | 643 | 987 | 5595 |
| | | CDD | 0 | 0 | 0 | 0 | 35 | 134 | 265 | 221 | 59 | 8 | 0 | 0 | 722 |
| 024 | BURGETTSTOWN 2 W | HDD | 1196 | 1022 | 844 | 534 | 281 | 65 | 14 | 35 | 134 | 451 | 714 | 1042 | 6332 |
| | | CDD | 0 | 0 | 0 | 0 | 25 | 78 | 155 | 139 | 28 | 3 | 0 | 0 | 428 |
| 025 | BUTLER 2 SW | HDD | 1242 | 1058 | 901 | 559 | 282 | 73 | 15 | 33 | 142 | 479 | 754 | 1075 | 6613 |
| | | CDD | 0 | 0 | 0 | 0 | 27 | 90 | 159 | 135 | 27 | 3 | 0 | 0 | 441 |
| 026 | CANTON | HDD | 1310 | 1124 | 967 | 609 | 311 | 92 | 24 | 50 | 187 | 534 | 802 | 1145 | 7155 |
| | | CDD | 0 | 0 | 0 | 0 | 9 | 46 | 121 | 100 | 10 | 0 | 0 | 0 | 286 |
| 029 | CHALK HILL 2 ENE | HDD | 1206 | 1007 | 840 | 507 | 260 | 72 | 19 | 38 | 157 | 469 | 750 | 1060 | 6385 |
| | | CDD | 0 | 0 | 0 | 0 | 21 | 68 | 128 | 103 | 22 | 3 | 0 | 0 | 345 |
| 030 | CHAMBERSBURG 1 ESE | HDD | 1131 | 934 | 762 | 419 | 172 | 18 | 4 | 10 | 80 | 383 | 666 | 987 | 5566 |
| | | CDD | 0 | 0 | 0 | 1 | 49 | 155 | 272 | 223 | 63 | 6 | 0 | 0 | 769 |
| 033 | CLARION 3 SW | HDD | 1287 | 1106 | 930 | 584 | 290 | 90 | 28 | 42 | 153 | 495 | 800 | 1129 | 6934 |
| | | CDD | 0 | 0 | 0 | 0 | 29 | 85 | 154 | 126 | 19 | 0 | 0 | 0 | 413 |
| 036 | CLERMONT 8 SW | HDD | 1321 | 1138 | 972 | 622 | 329 | 112 | 42 | 69 | 205 | 536 | 817 | 1156 | 7319 |
| | | CDD | 0 | 0 | 0 | 0 | 9 | 33 | 85 | 69 | 7 | 0 | 0 | 0 | 203 |
| 037 | COATESVILLE 2 W | HDD | 1128 | 952 | 782 | 450 | 185 | 23 | 1 | 5 | 68 | 371 | 657 | 975 | 5597 |
| | | CDD | 0 | 0 | 0 | 0 | 32 | 135 | 265 | 224 | 54 | 6 | 0 | 0 | 716 |
| 038 | CONFLUENCE 1 SW DAM | HDD | 1193 | 1002 | 834 | 500 | 237 | 40 | 6 | 16 | 109 | 430 | 728 | 1049 | 6144 |
| | | CDD | 0 | 0 | 0 | 0 | 36 | 105 | 199 | 175 | 50 | 5 | 0 | 0 | 570 |
| 043 | CORRY | HDD | 1278 | 1098 | 924 | 570 | 284 | 79 | 15 | 37 | 150 | 468 | 765 | 1109 | 6777 |
| | | CDD | 0 | 0 | 0 | 0 | 21 | 73 | 130 | 105 | 16 | 3 | 0 | 0 | 348 |
| 044 | COUDERSPORT 4 NW | HDD | 1350 | 1139 | 1000 | 618 | 322 | 107 | 41 | 68 | 215 | 544 | 855 | 1211 | 7470 |
| | | CDD | 0 | 0 | 0 | 0 | 14 | 43 | 80 | 65 | 4 | 0 | 0 | 0 | 206 |
| 049 | DERRY 4 SW | HDD | 1152 | 976 | 812 | 489 | 231 | 44 | 5 | 14 | 81 | 394 | 681 | 1005 | 5884 |
| | | CDD | 0 | 0 | 0 | 0 | 51 | 126 | 237 | 200 | 60 | 8 | 0 | 0 | 682 |
| 050 | DEVAULT 1 W | HDD | 1101 | 907 | 750 | 421 | 147 | 20 | 1 | 2 | 47 | 305 | 619 | 939 | 5259 |
| | | CDD | 0 | 0 | 0 | 1 | 53 | 181 | 327 | 284 | 102 | 18 | 0 | 0 | 966 |
| 051 | DONEGAL 2 NW | HDD | 1245 | 1050 | 901 | 580 | 297 | 82 | 20 | 55 | 153 | 473 | 748 | 1080 | 6684 |
| | | CDD | 0 | 0 | 0 | 0 | 17 | 67 | 136 | 136 | 33 | 4 | 0 | 0 | 393 |
| 052 | DONORA 1 SW | HDD | 1109 | 937 | 762 | 453 | 183 | 31 | 4 | 6 | 54 | 335 | 637 | 951 | 5462 |
| | | CDD | 0 | 0 | 0 | 1 | 54 | 158 | 277 | 239 | 88 | 12 | 0 | 0 | 829 |
| 054 | DUBOIS JEFFERSON CO AP | HDD | 1286 | 1082 | 922 | 565 | 283 | 71 | 20 | 37 | 162 | 492 | 783 | 1131 | 6834 |
| | | CDD | 0 | 0 | 0 | 0 | 33 | 70 | 145 | 116 | 18 | 2 | 0 | 0 | 384 |
| 055 | EBENSBURG SEWAGE PLANT | HDD | 1231 | 1045 | 882 | 548 | 281 | 79 | 20 | 40 | 147 | 468 | 754 | 1090 | 6585 |
| | | CDD | 0 | 0 | 0 | 0 | 17 | 60 | 125 | 109 | 22 | 2 | 0 | 0 | 335 |
| 056 | EISENHOWER NATL HIS SIT | HDD | 1113 | 938 | 749 | 437 | 173 | 21 | 1 | 5 | 59 | 345 | 645 | 941 | 5427 |
| | | CDD | 0 | 0 | 0 | 0 | 34 | 140 | 287 | 242 | 69 | 8 | 0 | 0 | 780 |
| 057 | EMPORIUM | HDD | 1288 | 1094 | 916 | 556 | 271 | 68 | 13 | 25 | 134 | 473 | 778 | 1131 | 6747 |
| | | CDD | 0 | 0 | 0 | 0 | 24 | 78 | 163 | 134 | 21 | 1 | 0 | 0 | 421 |
| 059 | ERIE AP | HDD* | 1196 | 1046 | 900 | 567 | 260 | 58 | 4 | 15 | 116 | 386 | 679 | 1016 | 6243 |
| | | CDD* | 0 | 0 | 1 | 5 | 30 | 115 | 208 | 183 | 71 | 7 | 0 | 0 | 620 |
| 060 | EVERETT | HDD | 1196 | 997 | 845 | 507 | 239 | 71 | 13 | 19 | 113 | 440 | 733 | 1045 | 6218 |
| | | CDD | 0 | 0 | 0 | 1 | 29 | 109 | 195 | 153 | 28 | 4 | 0 | 0 | 519 |
| 061 | FORD CITY 4 S DAM | HDD | 1183 | 1000 | 822 | 479 | 226 | 48 | 8 | 14 | 91 | 410 | 691 | 1022 | 5994 |
| | | CDD | 0 | 0 | 0 | 1 | 43 | 132 | 227 | 194 | 53 | 5 | 0 | 0 | 655 |



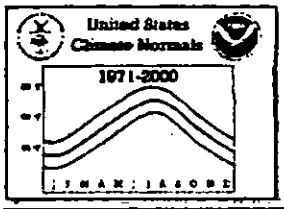

# CLIMATOGRAPHY OF THE UNITED STATES NO. 81

Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days
1971-2000

## PENNSYLVANIA



| No. | Station Name | Element | DEGREE DAYS (Total) JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 062 | FRANCIS E WALTER DAM | HDD | 1375 | 1179 | 1018 | 664 | 348 | 125 | 41 | 77 | 248 | 588 | 857 | 1205 | 7725 |
| | | CDD | 0 | 0 | 0 | 0 | 5 | 29 | 85 | 71 | 6 | 0 | 0 | 0 | 196 |
| 063 | FRANKLIN | HDD | 1232 | 1064 | 908 | 549 | 268 | 58 | 6 | 23 | 115 | 445 | 726 | 1064 | 6458 |
| | | CDD | 0 | 0 | 0 | 0 | 32 | 99 | 181 | 156 | 29 | 3 | 0 | 0 | 500 |
| 064 | FREELAND | HDD | 1349 | 1149 | 1011 | 629 | 326 | 118 | 23 | 47 | 206 | 549 | 846 | 1213 | 7466 |
| | | CDD | 0 | 0 | 0 | 0 | 10 | 34 | 106 | 77 | 7 | 0 | 0 | 0 | 234 |
| 071 | GRATERFORD 1 E | HDD | 1146 | 968 | 804 | 464 | 198 | 38 | 0 | 13 | 97 | 393 | 652 | 986 | 5759 |
| | | CDD | 0 | 0 | 0 | 0 | 32 | 133 | 258 | 202 | 57 | 8 | 0 | 0 | 690 |
| 073 | GREENVILLE 2 NE | HDD | 1264 | 1072 | 903 | 550 | 261 | 53 | 9 | 28 | 127 | 457 | 746 | 1092 | 6562 |
| | | CDD | 0 | 0 | 0 | 0 | 35 | 102 | 183 | 154 | 33 | 5 | 0 | 0 | 512 |
| 074 | HAMBURG | HDD | 1173 | 981 | 799 | 454 | 177 | 24 | 2 | 5 | 83 | 411 | 682 | 1021 | 5812 |
| | | CDD | 0 | 0 | 0 | 0 | 39 | 149 | 274 | 221 | 48 | 6 | 0 | 0 | 737 |
| 075 | HANOVER | HDD | 1081 | 906 | 740 | 400 | 155 | 13 | 0 | 7 | 62 | 349 | 611 | 933 | 5257 |
| | | CDD | 0 | 0 | 0 | 1 | 58 | 186 | 321 | 264 | 88 | 15 | 0 | 0 | 933 |
| 076 | HARRISBURG CAPITAL CITY | HDD | 1076 | 901 | 723 | 390 | 148 | 14 | 0 | 1 | 52 | 338 | 621 | 937 | 5201 |
| | | CDD | 0 | 0 | 0 | 1 | 54 | 186 | 337 | 279 | 87 | 11 | 0 | 0 | 955 |
| 077 | HAWLEY 1 E | HDD | 1298 | 1119 | 956 | 603 | 299 | 95 | 26 | 39 | 178 | 511 | 782 | 1133 | 7039 |
| | | CDD | 0 | 0 | 0 | 0 | 9 | 58 | 129 | 96 | 8 | 0 | 0 | 0 | 300 |
| 079 | HOLTWOOD | HDD | 1079 | 904 | 738 | 412 | 156 | 12 | 0 | 3 | 54 | 323 | 607 | 928 | 5216 |
| | | CDD | 0 | 0 | 0 | 2 | 60 | 187 | 327 | 287 | 106 | 13 | 0 | 0 | 982 |
| 082 | HOPEWELL MORGANTOWN | HDD | 1132 | 958 | 787 | 458 | 191 | 28 | 4 | 6 | 77 | 384 | 650 | 974 | 5649 |
| | | CDD | 0 | 0 | 0 | 0 | 26 | 114 | 237 | 192 | 41 | 4 | 0 | 0 | 614 |
| 084 | INDIANA 3 SE | HDD | 1168 | 985 | 807 | 483 | 230 | 52 | 6 | 15 | 107 | 408 | 687 | 1009 | 5957 |
| | | CDD | 0 | 0 | 0 | 0 | 36 | 102 | 179 | 150 | 42 | 7 | 0 | 0 | 516 |
| 085 | JAMESTOWN 2 NW | HDD | 1272 | 1090 | 919 | 568 | 276 | 58 | 10 | 31 | 133 | 455 | 739 | 1090 | 6641 |
| | | CDD | 0 | 0 | 0 | 0 | 29 | 89 | 163 | 138 | 26 | 2 | 0 | 0 | 447 |
| 086 | JOHNSTOWN | HDD | 1111 | 925 | 762 | 401 | 172 | 24 | 1 | 6 | 61 | 375 | 643 | 974 | 5455 |
| | | CDD | 0 | 0 | 0 | 1 | 61 | 169 | 275 | 222 | 65 | 10 | 0 | 0 | 803 |
| 087 | KANE 1 NNE | HDD | 1388 | 1210 | 1066 | 701 | 405 | 158 | 66 | 107 | 277 | 610 | 882 | 1224 | 8094 |
| | | CDD | 0 | 0 | 0 | 0 | 5 | 21 | 48 | 44 | 2 | 0 | 0 | 0 | 120 |
| 088 | KEGG | HDD | 1122 | 929 | 774 | 430 | 183 | 27 | 6 | 12 | 80 | 389 | 670 | 988 | 5610 |
| | | CDD | 0 | 0 | 0 | 1 | 38 | 128 | 234 | 197 | 55 | 5 | 0 | 0 | 658 |
| 092 | LANCASTER 2 NE FILT PLT | HDD | 1113 | 940 | 756 | 426 | 159 | 15 | 0 | 4 | 62 | 359 | 653 | 961 | 5448 |
| | | CDD | 0 | 0 | 0 | 0 | 36 | 156 | 291 | 248 | 71 | 7 | 0 | 0 | 809 |
| 093 | LANDISVILLE 2 NW | HDD | 1110 | 926 | 738 | 413 | 148 | 16 | 0 | 6 | 67 | 364 | 649 | 964 | 5401 |
| | | CDD | 0 | 0 | 0 | 0 | 43 | 169 | 272 | 218 | 61 | 8 | 0 | 0 | 771 |
| 094 | LAUREL MOUNTAIN | HDD | 1305 | 1125 | 972 | 632 | 340 | 123 | 51 | 69 | 193 | 521 | 818 | 1155 | 7304 |
| | | CDD | 0 | 0 | 0 | 0 | 16 | 57 | 109 | 91 | 18 | 4 | 0 | 0 | 295 |
| 095 | LAURELTON CENTER | HDD | 1172 | 964 | 791 | 422 | 168 | 20 | 4 | 12 | 87 | 390 | 698 | 1036 | 5764 |
| | | CDD | 0 | 0 | 0 | 1 | 49 | 138 | 256 | 212 | 51 | 8 | 0 | 0 | 715 |
| 096 | LEBANON 2 W | HDD | 1169 | 984 | 806 | 474 | 208 | 39 | 5 | 13 | 106 | 427 | 712 | 1017 | 5960 |
| | | CDD | 0 | 0 | 0 | 0 | 26 | 121 | 227 | 166 | 33 | 5 | 0 | 0 | 578 |
| 100 | LEWISTOWN | HDD | 1171 | 980 | 807 | 457 | 196 | 30 | 5 | 9 | 90 | 404 | 691 | 1014 | 5854 |
| | | CDD | 0 | 0 | 0 | 0 | 42 | 120 | 241 | 199 | 51 | 4 | 0 | 0 | 657 |
| 101 | LINESVILLE 1 S | HDD | 1301 | 1131 | 966 | 592 | 289 | 60 | 6 | 33 | 142 | 474 | 765 | 1106 | 6865 |
| | | CDD | 0 | 0 | 0 | 0 | 28 | 87 | 161 | 130 | 19 | 3 | 0 | 0 | 428 |
| 102 | LOCK HAVEN SEWAGE PLANT | HDD | 1228 | 1046 | 868 | 510 | 228 | 43 | 7 | 13 | 108 | 443 | 739 | 1061 | 6294 |
| | | CDD | 0 | 0 | 0 | 0 | 34 | 106 | 217 | 171 | 41 | 4 | 0 | 0 | 573 |
| 105 | MADERA 2 SE | HDD | 1312 | 1116 | 967 | 613 | 322 | 93 | 25 | 51 | 196 | 550 | 814 | 1156 | 7215 |
| | | CDD | 0 | 0 | 0 | 0 | 13 | 46 | 110 | 88 | 13 | 0 | 0 | 0 | 270 |
| 108 | MARCUS HOOK | HDD | 971 | 803 | 644 | 323 | 108 | 4 | 0 | 0 | 23 | 250 | 518 | 825 | 4469 |
| | | CDD | 0 | 0 | 0 | 4 | 98 | 267 | 424 | 369 | 149 | 22 | 0 | 0 | 1333 |
| 109 | MARION CENTER 2 SE | HDD | 1293 | 1101 | 924 | 585 | 289 | 85 | 27 | 42 | 162 | 491 | 791 | 1119 | 6909 |
| | | CDD | 0 | 0 | 0 | 0 | 30 | 80 | 147 | 122 | 20 | 1 | 0 | 0 | 400 |
| 110 | MATAMORAS | HDD | 1240 | 1055 | 873 | 519 | 223 | 41 | 7 | 17 | 113 | 439 | 741 | 1076 | 6344 |
| | | CDD | 0 | 0 | 0 | 0 | 21 | 93 | 208 | 171 | 25 | 2 | 0 | 0 | 520 |
| 111 | MCKEESPORT | HDD | 1128 | 971 | 792 | 455 | 218 | 39 | 1 | 10 | 76 | 388 | 665 | 984 | 5727 |
| | | CDD | 0 | 0 | 0 | 1 | 48 | 133 | 252 | 213 | 55 | 7 | 0 | 0 | 709 |
| 112 | MEADVILLE 1 S | HDD | 1271 | 1096 | 940 | 588 | 296 | 72 | 13 | 30 | 134 | 456 | 748 | 1095 | 6739 |
| | | CDD | 0 | 0 | 0 | 0 | 26 | 77 | 145 | 129 | 22 | 2 | 0 | 0 | 401 |
| 113 | MERCER | HDD | 1217 | 1013 | 835 | 508 | 252 | 66 | 14 | 33 | 124 | 431 | 719 | 1059 | 6271 |
| | | CDD | 0 | 0 | 0 | 0 | 35 | 91 | 162 | 147 | 41 | 6 | 0 | 0 | 482 |
| 114 | MERCERSBURG 1 E | HDD | 1079 | 895 | 748 | 397 | 175 | 17 | 3 | 6 | 79 | 391 | 648 | 976 | 5414 |
| | | CDD | 0 | 0 | 0 | 1 | 38 | 162 | 282 | 227 | 68 | 7 | 0 | 0 | 785 |
| 117 | MILLVILLE 2 SW | HDD | 1271 | 1079 | 913 | 554 | 263 | 62 | 12 | 22 | 146 | 478 | 766 | 1106 | 6672 |
| | | CDD | 0 | 0 | 0 | 0 | 16 | 74 | 169 | 127 | 17 | 1 | 0 | 0 | 404 |
| 118 | MONTGOMERY LOCK & DAM | HDD | 1175 | 990 | 827 | 481 | 201 | 41 | 8 | 19 | 91 | 398 | 693 | 1011 | 5935 |
| | | CDD | 0 | 0 | 0 | 1 | 47 | 138 | 240 | 189 | 61 | 4 | 0 | 0 | 680 |




**CLIMATOGRAPHY OF THE UNITED STATES NO. 81**
*Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days*
**1971-2000**

## PENNSYLVANIA



DEGREE DAYS (Total)

| No. | Station Name | Element | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 185 | WAYNESBURG 1 E | HDD | 1145 | 971 | 800 | 492 | 232 | 47 | 9 | 21 | 101 | 430 | 703 | 999 | 5950 |
| | | CDD | 0 | 0 | 0 | 0 | 34 | 111 | 201 | 170 | 39 | 6 | 0 | 0 | 561 |
| 186 | WELLSBORO 4 SW | HDD | 1355 | 1159 | 1021 | 650 | 341 | 116 | 43 | 60 | 211 | 534 | 829 | 1186 | 7505 |
| | | CDD | 0 | 0 | 0 | 0 | 9 | 36 | 90 | 66 | 4 | 0 | 0 | 0 | 205 |
| 187 | WEST CHESTER 2 NW | HDD | 1083 | 905 | 736 | 406 | 151 | 22 | 2 | 4 | 66 | 357 | 611 | 936 | 5279 |
| | | CDD | 0 | 0 | 0 | 1 | 39 | 168 | 303 | 245 | 74 | 7 | 0 | 0 | 837 |
| 191 | WILKES BRE SCTN AP AVOC | HDD* | 1214 | 1027 | 857 | 510 | 219 | 53 | 9 | 18 | 138 | 431 | 711 | 1047 | 6234 |
| | | CDD* | 0 | 0 | 1 | 5 | 36 | 114 | 220 | 174 | 57 | 4 | 0 | 0 | 611 |
| 193 | WILLIAMSPORT LYCOMING A | HDD* | 1211 | 1014 | 824 | 471 | 196 | 38 | 6 | 12 | 116 | 417 | 710 | 1048 | 6063 |
| | | CDD* | 0 | 0 | 0 | 6 | 39 | 135 | 251 | 206 | 68 | 4 | 0 | 0 | 709 |
| 194 | WILLOW GROVE NAS | HDD | 1037 | 871 | 705 | 378 | 128 | 11 | 0 | 0 | 43 | 306 | 563 | 879 | 4921 |
| | | CDD | 0 | 0 | 0 | 2 | 56 | 209 | 351 | 295 | 101 | 17 | 0 | 0 | 1031 |
| 196 | YORK 3 SSW PUMP STN | HDD | 1087 | 896 | 712 | 394 | 143 | 18 | 1 | 2 | 59 | 342 | 633 | 946 | 5233 |
| | | CDD | 0 | 0 | 0 | 1 | 46 | 177 | 297 | 246 | 84 | 11 | 0 | 0 | 862 |

D. R. Woodruff

**PPL Electric Utilities Corporation**
**Response to Interrogatories of the**
**Office of Trial Staff, Set 1,**
**Dated March 31, 2004**
**Docket No. R-00049255**

Q.OTS-RE-8. Provide an electronic copy, in Excel with the formulas intact, that shows how the Company determined annualized sales for each class, based on the use of 20 year data. Include the following:

A. Number of customers
B. Actual Monthly Sales
C. Base Load
D. Weather sensitive load
E. Calculation of normalized weather sensitive load
F. Normalized monthly sales

A.OTS.RE-8. The annualization adjustment of sales for both the historic and future test years has two components. One component accounts for changes in the number of customers over the test year, and the other accounts for changes in usage. This second component recognizes changing KWH usage levels by existing customers, and is the average change over the past three years in average annual usage. Weather data is not used in the annualization process.

The budgeted sales level that reflects normal weather conditions for the test period, and to which the annualization adjustment is applied, is based on 20-year data. The forecast models, as described in the response to Question OTS-RE-7 of the Interrogatories of the Office of Trial Staff, Set I, dated March 31, 2004, do not reside in Excel format, but are in Metrix ND, a software program developed by RER, Inc. (now owned by Itron). The models produce a total sales forecast for each class, but do not produce separate base and weather-sensitive load forecasts. Actual monthly sales history is used in the forecast, along with actual weather data.

Attachment 1 provides a diskette with an electronic version in Excel format of the requested data for the number of customers and the actual monthly sales. No data is available for weather sensitive load, calculation of normalized weather sensitive load, and normalized monthly sales.

**PPL Electric Utilities Corporation**
**Summary of RS, RTS, and RTD Customers**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| 1 | | | Residential | Residential | Total | Percent | Percent |
| 2 | Year | Month | Electric Heat | General | Residential | Heat | Non-Heat |
| 3 | 2000 | 6 | 357,417 | 785,975 | 1,143,392.00 | 31.3% | 68.7% |
| 4 | 2000 | 7 | 348,905 | 766,367 | 1,115,272.00 | 31.3% | 68.7% |
| 5 | 2000 | 8 | 349,036 | 767,387 | 1,116,423.00 | 31.3% | 68.7% |
| 6 | 2000 | 9 | 349,495 | 771,337 | 1,120,832.00 | 31.2% | 68.8% |
| 7 | 2000 | 10 | 351,250 | 769,841 | 1,121,091.00 | 31.3% | 68.7% |
| 8 | 2000 | 11 | 353,954 | 777,900 | 1,131,854.00 | 31.3% | 68.7% |
| 9 | 2000 | 12 | 348,943 | 768,222 | 1,117,165.00 | 31.2% | 68.8% |
| 10 | 2001 | 1 | 351,214 | 773,937 | 1,125,151.00 | 31.2% | 68.8% |
| 11 | 2001 | 2 | 359,643 | 789,605 | 1,149,248.00 | 31.3% | 68.7% |
| 12 | 2001 | 3 | 349,579 | 771,306 | 1,120,885.00 | 31.2% | 68.8% |
| 13 | 2001 | 4 | 349,202 | 770,985 | 1,120,187.00 | 31.2% | 68.8% |
| 14 | 2001 | 5 | 352,616 | 777,464 | 1,130,080.00 | 31.2% | 68.8% |
| 15 | 2001 | 6 | 352,700 | 778,351 | 1,131,051.00 | 31.2% | 68.8% |
| 16 | 2001 | 7 | 353,030 | 779,929 | 1,132,959.00 | 31.2% | 68.8% |
| 17 | 2001 | 8 | 353,737 | 781,013 | 1,134,750.00 | 31.2% | 68.8% |
| 18 | 2001 | 9 | 353,133 | 779,957 | 1,133,090.00 | 31.2% | 68.8% |
| 19 | 2001 | 10 | 353,776 | 781,596 | 1,135,372.00 | 31.2% | 68.8% |
| 20 | 2001 | 11 | 353,874 | 781,321 | 1,135,195.00 | 31.2% | 68.8% |
| 21 | 2001 | 12 | 354,230 | 782,086 | 1,136,316.00 | 31.2% | 68.8% |
| 22 | 2002 | 1 | 353,822 | 783,493 | 1,137,315.00 | 31.1% | 68.9% |
| 23 | 2002 | 2 | 352,810 | 781,831 | 1,134,641.00 | 31.1% | 68.9% |
| 24 | 2002 | 3 | 355,312 | 786,000 | 1,141,312.00 | 31.1% | 68.9% |
| 25 | 2002 | 4 | 355,455 | 787,230 | 1,142,685.00 | 31.1% | 68.9% |
| 26 | 2002 | 5 | 356,904 | 790,383 | 1,147,287.00 | 31.1% | 68.9% |
| 27 | 2002 | 6 | 356,148 | 789,138 | 1,145,286.00 | 31.1% | 68.9% |
| 28 | 2002 | 7 | 355,338 | 787,513 | 1,142,851.00 | 31.1% | 68.9% |
| 29 | 2002 | 8 | 356,761 | 790,314 | 1,147,075.00 | 31.1% | 68.9% |
| 30 | 2002 | 9 | 354,871 | 787,275 | 1,142,146.00 | 31.1% | 68.9% |
| 31 | 2002 | 10 | 355,644 | 789,481 | 1,145,125.00 | 31.1% | 68.9% |
| 32 | 2002 | 11 | 355,055 | 786,173 | 1,141,228.00 | 31.1% | 68.9% |
| 33 | 2002 | 12 | 356,383 | 789,732 | 1,146,115.00 | 31.1% | 68.9% |
| 34 | 2003 | 1 | 354,736 | 787,030 | 1,141,766.00 | 31.1% | 68.9% |
| 35 | 2003 | 2 | 356,094 | 789,566 | 1,145,660.00 | 31.1% | 68.9% |
| 36 | 2003 | 3 | 355,473 | 787,026 | 1,142,499.00 | 31.1% | 68.9% |
| 37 | 2003 | 4 | 355,769 | 791,539 | 1,147,308.00 | 31.0% | 69.0% |
| 38 | 2003 | 5 | 358,583 | 798,032 | 1,156,615.00 | 31.0% | 69.0% |
| 39 | Average | | | | | 31.2% | 68.8% |

**PPL Electric Utilities Corporation**
**Summary of RS, RTS, and RTD Usage**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| 1 | | | Residential | Residential | Total | Percent | Percent |
| 2 | Year | Month | Electric Heat | General | Residential | Heat | Non-Heat |
| 3 | 2000 | 6 | 339,196,705 | 490,720,465 | 829,917,170 | 40.9% | 59.1% |
| 4 | 2000 | 7 | 353,565,504 | 561,607,972 | 915,173,476 | 38.6% | 61.4% |
| 5 | 2000 | 8 | 336,346,169 | 544,649,606 | 880,995,775 | 38.2% | 61.8% |
| 6 | 2000 | 9 | 332,494,590 | 519,576,755 | 852,071,345 | 39.0% | 61.0% |
| 7 | 2000 | 10 | 332,297,952 | 438,033,869 | 770,331,821 | 43.1% | 56.9% |
| 8 | 2000 | 11 | 414,445,278 | 443,281,734 | 857,727,012 | 48.3% | 51.7% |
| 9 | 2000 | 12 | 682,899,195 | 547,251,332 | 1,230,150,527 | 55.5% | 44.5% |
| 10 | 2001 | 1 | 912,318,090 | 629,087,017 | 1,541,405,107 | 59.2% | 40.8% |
| 11 | 2001 | 2 | 792,269,035 | 550,543,769 | 1,342,812,804 | 59.0% | 41.0% |
| 12 | 2001 | 3 | 703,223,695 | 519,154,792 | 1,222,378,487 | 57.5% | 42.5% |
| 13 | 2001 | 4 | 561,243,526 | 477,183,531 | 1,038,427,057 | 54.0% | 46.0% |
| 14 | 2001 | 5 | 362,893,775 | 438,054,750 | 800,948,525 | 45.3% | 54.7% |
| 15 | 2001 | 6 | 325,024,888 | 472,005,444 | 797,030,332 | 40.8% | 59.2% |
| 16 | 2001 | 7 | 363,547,556 | 594,296,396 | 957,843,952 | 38.0% | 62.0% |
| 17 | 2001 | 8 | 369,014,737 | 624,543,689 | 993,558,426 | 37.1% | 62.9% |
| 18 | 2001 | 9 | 352,122,791 | 573,147,603 | 925,270,394 | 38.1% | 61.9% |
| 19 | 2001 | 10 | 319,723,466 | 444,239,832 | 763,963,298 | 41.9% | 58.1% |
| 20 | 2001 | 11 | 400,508,422 | 451,842,819 | 852,351,241 | 47.0% | 53.0% |
| 21 | 2001 | 12 | 515,372,919 | 517,270,936 | 1,032,643,855 | 49.9% | 50.1% |
| 22 | 2002 | 1 | 785,812,095 | 630,382,009 | 1,416,194,104 | 55.5% | 44.5% |
| 23 | 2002 | 2 | 641,941,841 | 520,091,049 | 1,162,032,890 | 55.2% | 44.8% |
| 24 | 2002 | 3 | 596,871,295 | 491,294,936 | 1,088,166,231 | 54.9% | 45.1% |
| 25 | 2002 | 4 | 513,492,919 | 489,466,141 | 1,002,959,060 | 51.2% | 48.8% |
| 26 | 2002 | 5 | 387,306,416 | 463,857,411 | 851,163,827 | 45.5% | 54.5% |
| 27 | 2002 | 6 | 348,944,865 | 513,401,360 | 862,346,225 | 40.5% | 59.5% |
| 28 | 2002 | 7 | 393,757,453 | 676,563,623 | 1,070,321,076 | 36.8% | 63.2% |
| 29 | 2002 | 8 | 406,310,256 | 723,766,556 | 1,130,076,812 | 36.0% | 64.0% |
| 30 | 2002 | 9 | 371,085,423 | 626,591,900 | 997,677,323 | 37.2% | 62.8% |
| 31 | 2002 | 10 | 337,632,216 | 501,668,393 | 839,300,609 | 40.2% | 59.8% |
| 32 | 2002 | 11 | 467,972,442 | 484,082,261 | 952,054,703 | 49.2% | 50.8% |
| 33 | 2002 | 12 | 683,147,141 | 584,402,026 | 1,267,549,167 | 53.9% | 46.1% |
| 34 | 2003 | 1 | 869,640,774 | 650,599,132 | 1,520,239,906 | 57.2% | 42.8% |
| 35 | 2003 | 2 | 880,756,565 | 603,416,345 | 1,484,172,910 | 59.3% | 40.7% |
| 36 | 2003 | 3 | 810,481,769 | 566,321,595 | 1,376,803,364 | 58.9% | 41.1% |
| 37 | 2003 | 4 | 588,047,057 | 520,922,972 | 1,108,970,029 | 53.0% | 47.0% |
| 38 | 2003 | 5 | 403,018,094 | 463,314,464 | 866,332,558 | 46.5% | 53.5% |
| 39 | Average | | | | | 47.3% | 52.7% |

**PPL Electric Utilities Corporation**
**Summary of Rate Schedules RS, RTS, and RTD**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 1 | **Bills Breakdown: PPL Attachment IV-C, Page1-5** | | | | | |
| 2 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 3 | | | | | Heating | Non-Heating |
| 4 | Rate | | | Percent | Customer | Customer |
| 5 | Schedule | Customers | Bills | of Total | 31.2% | 68.8% |
| 6 | RS | 1,138,281 | 13,659,368 | 97.60% | 4,261,723 | 9,397,645 |
| 7 | RWO | 258 | 3,098 | 0.02% | 967 | 2,131 |
| 8 | RW1 | 202 | 2,426 | 0.02% | 757 | 1,669 |
| 9 | Subtotal | 1,138,741 | 13,664,892 | 97.64% | 4,263,446 | 9,401,446 |
| 10 | RTS | 14,211 | 170,529 | 1.22% | 53,205 | 117,324 |
| 11 | RTD | 272 | 3,261 | 0.02% | 1,017 | 2,244 |
| | | 0 | | | | |
| 12 | Total | 1,153,224 | 13,838,682 | 98.88% | 4,317,669 | 9,521,013 |
| 13 | **Bills Breakdown: Future Exhibit 1, Schedule D3, page 2** | | | | | |
| 14 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 15 | | | | | Heating | Non-Heating |
| 16 | Rate | | | Percent | Customer | Customer |
| 17 | Schedule | Customers | Bills | of Total | 31.2% | 68.8% |
| 18 | RS | 1,151,170 | 13,814,045 | 98.71% | 4,309,982 | 9,504,063 |
| 19 | RWO | 261 | 3,133 | 0.02% | 978 | 2,156 |
| 20 | RW1 | 204 | 2,453 | 0.02% | 765 | 1,688 |
| 21 | Subtotal | 1,151,636 | 13,819,632 | 98.75% | 4,311,725 | 9,507,907 |
| 22 | RTS | 14,342 | 172,104 | 1.23% | 53,696 | 118,408 |
| 23 | RTD | 274 | 3,288 | 0.02% | 1,026 | 2,262 |
| | | 0 | | | | |
| 24 | Total | 1,166,252 | 13,995,024 | 100.00% | 4,366,447 | 9,628,577 |

**PPL Electric Utilities Corporation**
**Summary of Rate Schedules RS, RTS, and RTD**
**R-00049255**

| | (A) | (B) | (C) | (D) |
|---|---|---|---|---|
| 1 | **Weighted Average Current Customer Charge** | | | |
| 2 | Rate | Customer | Percent | Customer Charge |
| 3 | Schedule | Charge | Of Total | Revenue |
| 4 | RS | $6.55 | 13,659,368 | $89,468,860 |
| 5 | RWO | $6.07 | 3,098 | $18,805 |
| 6 | RW1 | $12.61 | 2,426 | $30,592 |
| 7 | RTS | $15.21 | 170,529 | $2,593,746 |
| 8 | RTD | $12.67 | 3,261 | $41,317 |
| 9 | Totals | | 13,838,682 | $92,153,320 |
| 10 | Weighted Average | | | $6.659 |
| 11 | **Weighted Average Forecasted Customer Charge** | | | |
| 12 | Rate | Customer | Percent | Customer Charge |
| 13 | Schedule | Charge | Of Total | Revenue |
| 14 | RS | $6.55 | 13,814,045 | $90,481,998 |
| 15 | RWO | $6.07 | 3,133 | $19,018 |
| 16 | RW1 | $12.61 | 2,453 | $30,938 |
| 17 | RTS | $15.21 | 172,104 | $2,617,702 |
| 18 | RTD | $12.67 | 3,288 | $41,659 |
| 19 | Totals | | 13,995,024 | $93,191,315 |
| 20 | Weighted Average | | | $6.659 |

# PPL Electric Utilities Corporation
## Summary of Rate Schedules RS, RTS, and RTD
## R-00049255

| | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 1 | **Bills Breakdown: Future Exhibit 1, Schedule D3, page 2** | | | | | |
| 2 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 3 | Rate | | Percent | Usage Heating | Usage Non-Heating | |
| 4 | Schedule | kWh | of Total | 47.3% | 52.7% | |
| 5 | RS | 12,894,588,000 | 96.95% | 6,099,140,124 | 6,795,447,876 | |
| 6 | RTS | 399,999,000 | 3.01% | 189,199,527 | 210,799,473 | |
| 7 | RTD | 5,295,000 | 0.04% | 2,504,535 | 2,790,465 | |
| 8 | | | | | | |
| 9 | Total | 13,299,882,000 | 100.00% | 6,290,844,186 | 7,009,037,814 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10 | **Breakdown of Future Exhibit 1, Schedule D3, page 2** | | | | | |
| 11 | Rate | Present | Customer | | Usage | Usage |
| 12 | Schedule | Revenue | Charge Revenue | Usage Revenue | Heating 47.30% | Non-Heating 52.70% |
| 13 | RS | $290,356,394 | $90,531,954 | $199,824,440 | $94,516,960 | $105,307,480 |
| 14 | RTS | $3,472,873 | $2,617,702 | $855,171 | $404,496 | $450,675 |
| 15 | RTD | $118,811 | $41,659 | $77,152 | $36,493 | $40,659 |
| 16 | Total | $293,948,078 | $93,191,315 | $200,756,763 | $94,957,949 | $105,798,814 |

OTS Exhibit No. 3
Schedule 6

**PPL Electric Utilities Corporation**
**Actual NOAA Heating Degree Days**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| | | | | **2000** | | | |
| 1 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 2 | June | 33 | 14 | 59 | 32 | 106 | 27 |
| 3 | July | 3 | 0 | 26 | 6 | 29 | 7 |
| 4 | August | 16 | 4 | 32 | 16 | 52 | 13 |
| 5 | September | 176 | 99 | 202 | 171 | 477 | 119 |
| 6 | October | 372 | 293 | 410 | 369 | 1,075 | 269 |
| 7 | November | 729 | 638 | 794 | 745 | 2,161 | 540 |
| 8 | December | 1,224 | 1,187 | 1,289 | 1,263 | 3,700 | 925 |
| 9 | 2000 Totals | 2,553 | 2,235 | 2,812 | 2,602 | 7,600 | 1,900 |
| | | | | **2001** | | | |
| 10 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 11 | January | 1,168 | 1,127 | 1,181 | 1,157 | 3,476 | 869 |
| 12 | February | 928 | 836 | 973 | 914 | 2,737 | 684 |
| 13 | March | 878 | 826 | 982 | 918 | 2,686 | 672 |
| 14 | April | 434 | 402 | 491 | 447 | 1,327 | 332 |
| 15 | May | 164 | 112 | 187 | 147 | 463 | 116 |
| 16 | June | 28 | 16 | 45 | 28 | 89 | 22 |
| 17 | July | 15 | 1 | 28 | 10 | 44 | 11 |
| 18 | August | 0 | 0 | 0 | 1 | 0 | 0 |
| 19 | September | 119 | 82 | 156 | 122 | 357 | 89 |
| 20 | October | 354 | 288 | 370 | 370 | 1,012 | 253 |
| 21 | November | 533 | 477 | 537 | 562 | 1,547 | 387 |
| 22 | December | 822 | 774 | 863 | 875 | 2,459 | 615 |
| 23 | 2001 Totals | 5,443 | 4,941 | 5,813 | 5,551 | 16,197 | 4,049 |
| | | | | **2002** | | | |
| 24 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 25 | January | 946 | 900 | 975 | 962 | 2,821 | 705 |
| 26 | February | 801 | 766 | 840 | 817 | 2,407 | 602 |
| 27 | March | 739 | 699 | 775 | 783 | 2,213 | 553 |
| 28 | April | 410 | 343 | 459 | 428 | 1,212 | 303 |
| 29 | May | 261 | 189 | 309 | 269 | 759 | 190 |
| 30 | June | 15 | 5 | 35 | 25 | 55 | 14 |
| 31 | July | 0 | 0 | 4 | 2 | 4 | 1 |
| 32 | August | 4 | 1 | 7 | 4 | 12 | 3 |
| 33 | September | 48 | 22 | 68 | 41 | 138 | 35 |
| 34 | October | 425 | 395 | 483 | 451 | 1,303 | 326 |
| 35 | November | 717 | 663 | 751 | 741 | 2,131 | 533 |
| 36 | December | 1,091 | 1,047 | 1,110 | 1,130 | 3,248 | 812 |
| 37 | 2002 Totals | 5,457 | 5,030 | 5,816 | 5,653 | 16,303 | 4,076 |
| | | | | **2003** | | | |
| 38 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 39 | January | 1,278 | 1,213 | 1,363 | 1,307 | 3,854 | 964 |
| 40 | February | 1,091 | 1,067 | 1,126 | 1,101 | 3,284 | 821 |
| 41 | March | 774 | 774 | 852 | 863 | 2,400 | 600 |
| 42 | April | 485 | 427 | 520 | 470 | 1,432 | 358 |
| 43 | May | 234 | 193 | 247 | 226 | 674 | 169 |
| 44 | June | 56 | 51 | 88 | 66 | 195 | 49 |
| 45 | July | 0 | 0 | 2 | 2 | 2 | 1 |
| 46 | August | 0 | 0 | 10 | 5 | 10 | 3 |
| 47 | September | 40 | 28 | 80 | 65 | 148 | 37 |
| 48 | October | 413 | 384 | 496 | 466 | 1,293 | 323 |
| 49 | November | 550 | 513 | 611 | 591 | 1,674 | 419 |
| 50 | December | 984 | 950 | 1,031 | 1,024 | 3,989 | 997 |
| 51 | 2003 Totals | 5,905 | 5,600 | 6,426 | 6,186 | 18,955 | 4,739 |

**PPL Electric Utilities Corporation**
Weather Normalization Calculation - Heating
Rate Schedule RS - Heating
R-00049255
6/1/02 - 5/31/03

| | Month | No. of Heating Customers | Actual Sales (kWh) | Base Load Customers kWh | Heat Sensitive Load of Customers kWh | Actual DD | Heat Sensitive Load kWh/DD | NOAA Normal Heating Deg. Days | Normalized Heat Sensitive Load kWh/DD | Normalized Load (kWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | (A) | (B) | (C) | (D=B*BL) | (E=G-H) | (F) | (G=E/F) | H | (I=GxH) | (J=D+I or C) |
| 2 | Jun 02 | 356,148 | 348,944,865 | 338,110,691 | 10,834,174 | 14 | - | 35 | - | 348,944,865 |
| 3 | Jul | 355,338 | 393,757,453 | 337,341,714 | 56,415,739 | 1 | - | 8 | - | 393,757,453 |
| 4 | Aug | 356,761 | 406,310,256 | 338,692,645 | 67,617,611 | 3 | - | 10 | - | 406,310,256 |
| 5 | Sept | 354,871 | 371,085,423 | 336,898,365 | 34,187,058 | 35 | - | 103 | - | 371,085,423 |
| 6 | Oct | 355,644 | 337,632,216 | 337,632,216 | (0) | 326 | - | 395 | - | 337,632,216 |
| 7 | Nov | 355,055 | 467,972,442 | 337,073,046 | 130,899,396 | 533 | 245,590 | 679 | 166,755,610 | 503,828,656 |
| 8 | Dec 02 | 356,383 | 683,147,141 | 338,333,789 | 344,813,352 | 812 | 424,647 | 1,011 | 429,318,117 | 767,651,906 |
| 9 | Jan 03 | 354,736 | 869,640,774 | 336,770,202 | 532,870,572 | 964 | 552,770 | 1,165 | 643,977,050 | 980,747,252 |
| 10 | Feb | 356,094 | 880,756,565 | 338,059,426 | 542,697,139 | 821 | 661,020 | 977 | 645,816,540 | 983,875,966 |
| 11 | Mar | 355,473 | 810,481,769 | 337,469,876 | 473,011,893 | 600 | 788,353 | 800 | 630,682,400 | 968,152,276 |
| 12 | Apr | 355,769 | 588,047,057 | 337,750,885 | 250,296,172 | 358 | 699,151 | 460 | 321,609,460 | 659,360,345 |
| 13 | May 03 | 358,583 | 403,018,094 | 340,422,369 | 62,595,725 | 169 | 370,389 | 190 | 70,373,910 | 410,796,279 |
| 14 | Total | 4,270,855 | 6,560,794,055 | 4,054,555,224 | 2,506,238,831 | 4,636 | 3,741,920 | 5,833 | 2,908,533,087 | 7,132,142,893 |

15 Ave. No. of
16 Customers 355,905

17 Degree Day Variance: (Positive = Warmer Than Normal) 1,197

18 Normal Average Use per custome[redacted] kWh per month 20,039.5 kWh per year

| 19 | Base Load | Customers | kWh Sales |
|---|---|---|---|
| 20 | Oct | 355,644 | 337,632,216 |
| 21 | Total | 355,644 | 337,632,216 |

22 Base Load (kWh) Per Customer (BL): 949.4

OTS Exhibit No. 3
Schedule 7

OTS Exhibit No. 3
Schedule 8

**PPL Electric Utilities Corporation**
**Docket R-00049255**
**Present Rate Revenue - Residential Customers**
**per OTS**

| | Heating | Per Company | OTS Proposed Adjustment | OTS Recommended |
|---|---|---|---|---|
| | (A) | (B) | (C) | (D) |
| 1 | Heating Customer Bills | 4,366,447 (a) | 0 | 4,366,447 |
| 2 | Average Usage Per Customer | 1,441 (b) | 229 | 1,670 (f) |
| 3 | Heating Sales | 6,290,844,186 (c) | 1,000,934,022 | 7,291,778,208 |
| 4 | Weighted Customer Charge | $6.66 (d) | | $6.66 |
| 5 | Customer Charge Revenue (Line 1 Times line 4) | $29,075,690 | $0 | $29,075,690 |
| 6 | Average Price per kWh (Line 7 Divided by Line3) | $0.01509 | | $0.01509 |
| 7 | Total Kwh Revenue (Line 3 Times line 6) | $94,957,949 (e) | $15,108,726 | 110,066,675 |
| 8 | **Total Heating Revenue** (Line 5 Plus Line 7) | **$124,033,639** | **$15,108,726** | **$139,142,365** |

Sources:

(a) OTS Exhibit No. 3, Schedule 5, Page 1, Column E, Line 24
(b) Column B, Line 3 Divided by Line 1
(c) OTS Exhibit No. 3, Schedule 5, Page 3, Column D, Line 9
(d) OTS Exhibit No. 3, Schedule 5, Page 2, Column D, Line 20
(e) OTS Exhibit No. 3, Schedule 5, Page 3, Column E, Line 16
(f) OTS Exhibit No. 3, Schedule 7, Column D, Line 18

OTS Exhibit No. 3
Schedule 9

D. R. Woodruff

**PPL Electric Utilities Corporation**
**Response to Interrogatories of the**
**Office of Trial Staff, Set 1,**
**Dated March 31, 2004**
**Docket No. R-00049255**

Q.OTS-RE-7. Provide an electronic copy, in Excel with the formulas intact, that shows how the Company utilized regression analysis to determine normalized sales described on page 4 of PPL Statement No. 3.

A.OTS.RE-7. The forecast models that develop sales on a normal-weather basis do not reside in Excel format, but are in Metrix ND, a software program developed by RER, Inc. (now owned by Itron).

OTS Statement No. 3-SR
Witness: Joseph Kubas
Date: August 5, 2004
8/10/04 Hbg

DOCUMENT

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-00049255



Surrebuttal Testimony

of

Joseph Kubas

Office of Trial Staff



Concerning:

Present Rate Revenue

**Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?**

A. My name is Joseph Kubas and my business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg PA 17105-3265.

**Q. ARE YOU THE SAME JOSEPH KUBAS WHO SUBMITTED OTS STATEMENT NO. 3 ON JUNE 29, 2004?**

A. Yes, I am.

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. The purpose of my surrebuttal testimony is to revise the revenue adjustment that I originally proposed in OTS Statement No. 3, and address the rebuttal testimony of PPL Electric Utilities Corporation's (PPL or Company) witness David R. Woodruff filed as PPL Statement No. 3-R.

**A. Present Rate Revenue Adjustment**

**Q. WHAT ADJUSTMENT DID YOU PROPOSE TO PRESENT RATE REVENUE IN OTS STATEMENT NO. 3?**

A. I proposed that present rate revenue be increased by $15,109,000 (See OTS Statement No. 3, Page 16).

**Q. DID THE COMPANY DISCOVER AN ERROR IN YOUR CALCULATION?**

A. Yes. The Company discovered an error in my original calculation (See PPL Statement No. 3-R, Page 2).

**Q. WHAT IS YOUR REVISED RECOMMENDATION AFTER CORRECTING THIS ERROR?**

A. I recommend that present rate revenue be increased by $3,065,000 (See OTS Exhibit No. 3, Schedule 8, Column C, Line 8, Revised August 2004).

**B. Company Position**

**Q. DID MR. WOODRUFF'S ADDRESS YOUR PRESENT RATE REVENUE ADJUSTMENT IN HIS REBUTTAL TESTIMONY?**

A. Yes. Mr. Woodruff's addresses my present rate revenue adjustment in his rebuttal testimony (See PPL Statement 3-R).

**Q. IS MR. WOODRUFF'S OVERALL RECOMMENDATION CLEAR?**

A. No. I assume he is recommending that my adjustment be denied.

C. June - July 2002 Sales

**Q. WHAT DOES MR. WOODRUFF CLAIM REGARDING ACTUAL SALES DATA FOR JUNE AND JULY OF 2002?**

A. Mr. Woodruff claims that the actual kilowatt-hour (kWh) that I used for June and July 2002 are incorrect (See PPL Statement No. 3-R, Page 3).

**Q. ARE THE ACTUAL SALES FIGURES FOR RESIDENTIAL HEATING CUSTOMERS INCORRECT?**

A. No. I reviewed the response to OTS-8 and it clearly indicates that residential heating customers used 348,944,865 kWh in June and 393,757,453 kWh in July (See OTS Exhibit No. 3, Schedule 4, Column C, Lines 27 and 28). Schedule 4 is a paper copy of the electronic spreadsheet provided to OTS by the Company. The June and July sales figures are the exact numbers as shown on OTS Exhibit No. 3, Schedule 7, Column C, Lines 2-3.

D. RTS and RTD Customers

**Q. WHAT DOES MR. WOODRUFF CLAIM REGARDING RESIDENTIAL THERMAL STORAGE (RTS) AND RESIDENTIAL TIME OF DAY (RTD) CUSTOMERS?**

A. Mr. Woodruff claims that all RTS and RTD rate schedule customers are classified as heating customers (See PPL Statement No. 3-R, Page 3).

**Q. DO YOU ACCEPT MR. WOODRUFF'S REBUTTAL CLAIM THAT ALL RTS AND RTD CUSTOMERS ARE CLASSIFIED AS RESIDENTIAL HEATING CUSTOMERS?**

A. Yes.

**Q. DID YOU ADJUST YOUR CALCULATION TO REFLECT THIS CHANGE?**

A. Yes. I show this revision and incorporate the change in the revised adjustment described above (See OTS Exhibit No. 3, Schedule 5, Revised August 2004).

**E. Weather Data**

**Q. WHAT IS ONE OF MR. WOODRUFF'S CRITICISMS CONCERNING WEATHER DATA THAT I UTILIZED TO CALCULATE MY PRESENT REVENUE ADJUSTMENT?**

A. Mr. Woodruff claims that I made an error in calculating normal Heating Degree Days (HDD) (See PPL Statement No. 3-R, Page 2).

**Q. WHAT IS THE BASIS FOR MR. WOODRUFF'S OPINION?**

A. He believes my calculation of normal HDD is flawed because I used Capital City Airport data on OTS Schedule 3, Page 1, Column C and Middletown - Harrisburg Airport data on OTS Schedule 6, Column C (See PPL Statement No. 3-R, Page 2).

**Q. WHY DID YOU UTILIZE CAPITAL CITY AIRPORT DATA ON OTS SCHEDULE 3, PAGE 1, COLUMN C AND MIDDLETOWN - HARRISBURG AIRPORT DATA ON OTS SCHEDULE 6, COLUMN C?**

A. I used Middletown - Harrisburg airport on Schedule 6 because Middletown - Harrisburg airport is the local weather station that the Company used (See PPL Statement No. 3, Page 4). I used Capital City Airport data as the **official 30-year** data because this is the local station that NOAA uses in Publication No. 81 - "The Heating and Cooling Degree Days 1971 - 2000" (30-year data). I contacted NOAA by telephone and they indicated that there is only one weather station in the Harrisburg area at this time located at the Middletown - Harrisburg airport. NOAA also indicated that they treat the two airports as one location for weather reporting purposes. NOAA also indicated that the reference to Capital City Airport in Publication No. 81 is mostly likely an error and it should be listed as Middletown - Harrisburg airport.

**F. 30 Year - Normal NOAA Data**

**Q. WHAT IS ANOTHER ONE OF MR. WOODRUFF'S CLAIMS CONCERNING WEATHER DATA?**

A. Mr. Woodruff claims that the Company should use 20-year data to determine normal HDD (See PPL Statement No. 3-R, Page 7).

**Q. WHAT NORMALIZED PERIOD DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY?**

A. I recommended that the Company use **official** 30-year normal NOAA data to normalize sales (See OTS Statement No. 3, Page 9).

**Q. DID MR. WOODRUFF DESCRIBE WHY THE COMPANY USED 20-YEAR DATA RATHER THAN 30-YEAR DATA?**

A. Yes. Mr. Woodruff gave two reasons. First, he claims that the Company only has 20 years worth of actual billing and weather data. Second, Mr. Woodruff claims that in order to be consistent with PJM it "elected" to use 20-year data to normalize weather (See PPL Statement No. 3-R, Page 7).

**Q. IS MR. WOODRUFF'S FIRST CLAIM THAT THE COMPANY LACKS THE NECESSARY DATA A VALID REASON?**

A. No. Official NOAA data is available for at least the past 35 years. In addition, actual sales data from the 1970s, through the 1990s is not used in the annualization of 2002 or 2003 sales data.

**Q. LOOKING AT HIS SECOND REASON, DOES IT MATTER WHAT PJM DECIDES TO USE TO FORECAST SALES?**

A. No. If PJM chooses a time-period or method that is inconsistent with NOAA, and the Commission, that is their choice. When the Commission establishes rates, I recommend that the official 30-year NOAA data, as published by NOAA, be used. There is no reason to change the method or time period accepted by this Commission in the past. The Company has failed to present any compelling reason for the Commission to change its long accepted practice of relying on official 30 -year NOAA data in establishing rates.

**Q. DID THE COMPANY ADDRESS WHY IT DID NOT USE "OFFICIAL" NOAA DATA WHEN IT DETERMINED HDD?**

A. Yes. Mr. Woodruff states that the Company would rather rely on weather data from a private company named "Meteorlogix" rather than rely on official NOAA data. Mr. Woodruff even acknowledged that Meteorlogix data is "massaged" and

"reviewed" by meteorologists at Meteorlogix before it is given to PPL (See PPL Statement No. 3, Page 6-7). In Contrast, the official 30-year NOAA data is available to everyone and everyone can utilize this standard data without massaging and reviewing by unknown meteorologists and Meteorlogix.

**Q. SHOULD THE COMMISSION RELY ON DATA "MASSAGED" AND "REVIEWED" BY AN OUTSIDE PARTY, OR DATA DIRECTLY FROM NOAA TO DETERMINE NORMAL HDD?**

A. Obviously, the Commission should rely on official NOAA data to determine normal HDD and establish rates. The other parties and the Commission have no way of knowing what massaging the meteorologists at Meteorlogix did to the data. Therefore, I believe any "massaged" data from "Meteorlogix" leaves a lot of unanswered questions and can not be relied upon in this case.

## G. Forecasting Model

**Q. PLEASE SUMMARIZE THE FORECASTING MODEL ISSUES RAISED BY MR. WOODRUFF.**

A. Mr. Woodruff states that my use of a base month is incorrect and my adjustment fails to consider the affects of monthly billing, electric use for cooling, daylight, and holidays.

**Q. DID THE COMPANY EXPLAIN OR PROVIDE ANY DETAILS OF HOW EACH OF THE ITEMS IS REFLECTED IN ITS MODEL?**

A. No. Just like in the direct case, the Company chose to keep the Forecasting Model (Model), a secret in the Rebuttal phase of the case. Even given a second chance in rebuttal to provide the model, or even explain it, the Company chose not to provide the Model. Only the Company knows the true impact that these issues may have on sales. Since there is **no** evidence in the record as to how the Company considered each of these items, the Commission has no way of knowing how the Company considered each of these inputs. I believe that since the Company decided to keep the Model a secret, which is their choice, it has failed to meet its burden of proof that present rate revenue for residential heating customers is reasonable, and should be approved by the Commission.

## H. Future Test Year Sales

**Q. PLEASE SUMMARIZE THE FUTURE TEST YEAR SCHEDULES PRESENTED BY MR. WOODRUFF.**

A. Mr. Woodruff included a schedule in his rebuttal testimony that he believes proves that actual sales in the first half of the test year are 1.8% below what the Model forecasted (See PPL Statement No 3, Page 8 and Schedule DRW-2, Page 2 of 2).

**Q. WHY SHOULD THE COMMISSION NOT RELY ON THIS SCHEDULE AND THE MODEL USED TO GENERATE THE RESULTS?**

A. First, the Schedule includes a weather adjustment under column D. As described above, the Company uses 20-year data that was massaged by a third party to determine normal weather. Since the Company uses its own data rather than official NOAA data, the numbers under Column D are not based on actual 30-year NOAA data. Therefore, the numbers under Columns E and F are unreliable, including the 1.8% variance. Second, it shows that the whole Model and use of 20-year data is unreliable for forecasting sales in three of the coldest months: January, February, and March, with variances ranging from -3.6% and a +9.2%, back to -3.6% (See PPL Schedule DRW-2, Page 2, Table 3). Third, this is only a snapshot of a six-month period that was produced by a flawed model.

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

A. Yes, it does.

OTS Exhibit No. 3-SR
Witness: Joseph Kubas
Date: August 5, 2004

8/10/04 Hbg

DOCUMENT

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-00049255

DOCKETED

AUG 18 2004

Exhibit to Accompany

the

Surrebuttal Testimony

of

Joseph Kubas

Office of Trial Staff

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SECRETARY'S BUREAU

Concerning:

Present Rate Revenue

**PPL Electric Utilities Corporation**
**Summary of Rate Schedules RS, RTS, and RTD**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 1 | **Bills Breakdown: PPL Attachment IV-C, Page1-5** | | | | | |
| 2 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 3 | | | | | | |
| 4 | Rate | | | Percent | Heating Customer | Non-Heating Customer |
| 5 | Schedule | Customers | Bills | of Total | 31.2% | 68.8% |
| 6 | RS | 1,138,281 | 13,659,368 | 97.60% | 4,261,723 | 9,397,645 |
| 7 | RWO | 258 | 3,098 | 0.02% | 967 | 2,131 |
| 8 | RW1 | 202 | 2,426 | 0.02% | 757 | 1,669 |
| 9 | Subtotal | 1,138,741 | 13,664,892 | 97.64% | 4,263,446 | 9,401,446 |
| 10 | RTS | 14,211 | 170,529 | 1.22% | 170,529 | 0 |
| 11 | RTD | 272 | 3,261 | 0.02% | 3,261 | 0 |
| | | 0 | | | | |
| 12 | Total | 1,153,224 | 13,838,682 | 98.88% | 4,437,236 | 9,401,446 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 13 | **Bills Breakdown: Future Exhibit 1, Schedule D3, page 2** | | | | | |
| 14 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 15 | | | | | | |
| 16 | Rate | | | Percent | Heating Customer | Non-Heating Customer |
| 17 | Schedule | Customers | Bills | of Total | 31.2% | 68.8% |
| 18 | RS | 1,151,170 | 13,814,045 | 98.71% | 4,309,982 | 9,504;063 |
| 19 | RWO | 261 | 3,133 | 0.02% | 978 | 2,156 |
| 20 | RW1 | 204 | 2,453 | 0.02% | 765 | 1,688 |
| 21 | Subtotal | 1,151,636 | 13,819,632 | 98.75% | 4,311,725 | 9,507,907 |
| 22 | RTS * | 14,342 | 172,104 | 1.23% | 172,104 | 0 |
| 23 | RTD * | 274 | 3,288 | 0.02% | 3,288 | 0 |
| | | 0 | | | | |
| 24 | Total | 1,166,252 | 13,995,024 | 100.00% | 4,487,117 | 9,507,907 |

**PPL Electric Utilities Corporation**
**Summary of Rate Schedules RS, RTS, and RTD**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|
| 1 | **Bills Breakdown: Future Exhibit 1, Schedule D3, page 2** | | | | | |
| 2 | **Heating and Non Heating Percentage: OTS-8** | | | | | |
| 3 | Rate | | Percent | Usage Heating | Usage Non-Heating | |
| 4 | Schedule | kWh | of Total | 47.3% | 52.7% | |
| 5 | RS | 12,894,588,000 | 96.95% | 6,099,140,124 | 6,795,447,876 | |
| 6 | RTS | 399,999,000 | 3.01% | 399,999,000 | 0 | |
| 7 | RTD | 5,295,000 | 0.04% | 5,295,000 | 0 | |
| 8 | | | | | | |
| 9 | Total | 13,299,882,000 | 100.00% | 6,504,434,124 | 6,795,447,876 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10 | ***Breakdown of Future Exhibit 1, Schedule D3, page 2*** | | | | | |
| 11 | Rate | Present | Customer Charge | | Usage Heating | Usage Non-Heating |
| 12 | Schedule | Revenue | Revenue | Usage Revenue | 47.30% | 52.70% |
| 13 | RS | $290,356,394 | $90,531,954 | $199,824,440 | $94,516,960 | $105,307,480 |
| 14 | RTS | $3,472,873 | $2,617,702 | $855,171 | $855,171 | $0 |
| 15 | RTD | $118,811 | $41,659 | $77,152 | $77,152 | $0 |
| 16 | Total | $293,948,078 | $93,191,315 | $200,756,763 | $95,449,283 | $105,307,480 |

OTS Exhibit No. 3
Schedule 6
Revised August 2004

**PPL Electric Utilities Corporation**
**Actual NOAA Heating Degree Days**
**R-00049255**

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| | | | | 2000 | | | |
| 1 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 2 | June | 33 | 14 | 59 | 32 | 138 | 35 |
| 3 | July | 3 | 0 | 26 | 6 | 35 | 9 |
| 4 | August | 16 | 4 | 32 | 16 | 68 | 17 |
| 5 | September | 176 | 99 | 202 | 171 | 648 | 162 |
| 6 | October | 372 | 293 | 410 | 369 | 1,444 | 361 |
| 7 | November | 729 | 638 | 794 | 745 | 2,906 | 727 |
| 8 | December | 1,224 | 1,187 | 1,289 | 1,263 | 4,963 | 1,241 |
| 9 | 2000 Totals | 2,553 | 2,235 | 2,812 | 2,602 | 10,202 | 2,551 |
| | | | | 2001 | | | |
| 10 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 11 | January | 1,168 | 1,127 | 1,181 | 1,157 | 4,633 | 1,158 |
| 12 | February | 928 | 836 | 973 | 914 | 3,651 | 913 |
| 13 | March | 878 | 826 | 982 | 918 | 3,604 | 901 |
| 14 | April | 434 | 402 | 491 | 447 | 1,774 | 444 |
| 15 | May | 164 | 112 | 187 | 147 | 610 | 153 |
| 16 | June | 28 | 16 | 45 | 28 | 117 | 29 |
| 17 | July | 15 | 1 | 28 | 10 | 54 | 14 |
| 18 | August | 0 | 0 | 0 | 1 | 1 | 0 |
| 19 | September | 119 | 82 | 156 | 122 | 479 | 120 |
| 20 | October | 354 | 288 | 370 | 370 | 1,382 | 346 |
| 21 | November | 533 | 477 | 537 | 562 | 2,109 | 527 |
| 22 | December | 822 | 774 | 863 | 875 | 3,334 | 834 |
| 23 | 2001 Totals | 5,443 | 4,941 | 5,813 | 5,551 | 21,748 | 5,437 |
| | | | | 2002 | | | |
| 24 | Month | Allentown | Harrisburg | Scranton | Williamsport | Total | Average |
| 25 | January | 946 | 900 | 975 | 962 | 3,783 | 946 |
| 26 | February | 801 | 766 | 840 | 817 | 3,224 | 806 |
| 27 | March | 739 | 699 | 775 | 783 | 2,996 | 749 |
| 28 | April | 410 | 343 | 459 | 428 | 1,640 | 410 |
| 29 | May | 261 | 189 | 309 | 269 | 1,028 | 257 |
| 30 | June | 15 | 5 | 35 | 25 | 80 | 20 |
| 31 | July | 0 | 0 | 4 | 2 | 6 | 2 |
| 32 | August | 4 | 1 | 7 | 4 | 16 | 4 |
| 33 | September | 48 | 22 | 68 | 41 | 179 | 45 |
| 34 | October | 425 | 395 | 483 | 451 | 1,754 | 439 |
| 35 | November | 717 | 663 | 751 | 741 | 2,872 | 718 |
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| 45 | July | 0 | 0 | 2 | 2 | 4 | 1 |
| 46 | August | 0 | 0 | 10 | 5 | 15 | 4 |
| 47 | September | 40 | 28 | 80 | 65 | 213 | 53 |
| 48 | October | 413 | 384 | 496 | 466 | 1,759 | 440 |
| 49 | November | 550 | 513 | 611 | 591 | 2,265 | 566 |
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| 51 | 2003 Totals | 5,905 | 5,600 | 6,426 | 6,186 | 24,117 | 6,029 |

**PPL Electric Utilities Corporation**
Weather Normalization Calculation - Heating
Rate Schedule RS - Heating
R-00049255
6/1/02 - 5/31/03

| | Month | No. of Heating Customers | Actual Sales (kWh) | Base Load Customers kWh | Heat Sensitive Load of Customers kWh | Actual DD | Heat Sensitive Load kWh/DD | NOAA Normal Heating Deg. Days | Normalized Heat Sensitive Load kWh/DD | Normalized Load (kWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | (A) | (B) | (C) | (D=B*BL) | (E=C-D) | (F) | (G=E/F) | H | (I=GxH) | (J=D+I or C) |
| 2 | Jun 02 | 356,148 | 348,944,865 | 338,110,691 | 10,834,174 | 20 | - | 35 | - | 348,944,865 |
| 3 | Jul | 355,338 | 393,757,453 | 337,341,714 | 56,415,739 | 2 | - | 8 | - | 393,757,453 |
| 4 | Aug | 356,761 | 406,310,256 | 338,692,645 | 67,617,611 | 4 | - | 10 | - | 406,310,256 |
| 5 | Sept | 354,871 | 371,085,423 | 336,898,365 | 34,187,058 | 45 | - | 103 | - | 371,085,423 |
| 6 | Oct | 355,644 | 337,632,216 | 337,632,216 | (0) | 439 | - | 395 | - | 337,632,216 |
| 7 | Nov | 355,055 | 467,972,442 | 337,073,046 | 130,899,396 | 718 | 182,311 | 679 | 123,789,169 | 460,862,215 |
| 8 | Dec 02 | 356,383 | 683,147,141 | 338,333,789 | 344,813,352 | 1,095 | 314,898 | 1,011 | 318,361,878 | 656,695,667 |
| 9 | Jan 03 | 354,736 | 869,640,774 | 336,770,202 | 532,870,572 | 1,290 | 413,078 | 1,165 | 481,235,870 | 818,006,072 |
| 10 | Feb | 356,094 | 880,756,565 | 338,059,426 | 542,697,139 | 1,096 | 495,162 | 977 | 483,773,274 | 821,832,700 |
| 11 | Mar | 355,473 | 810,481,769 | 337,469,876 | 473,011,893 | 816 | 579,671 | 800 | 463,736,800 | 801,206,676 |
| 12 | Apr | 355,769 | 588,047,057 | 337,750,885 | 250,296,172 | 475 | 526,939 | 460 | 242,391,940 | 580,142,825 |
| 13 | May 03 | 358,583 | 403,018,094 | 340,422,369 | 62,595,725 | 225 | 278,203 | 190 | 52,858,570 | 393,280,939 |
| 14 | Total | 4,270,855 | 6,560,794,055 | 4,054,555,224 | 2,506,238,831 | 6,225 | 2,790,262 | 5,833 | 2,166,147,501 | 6,389,757,307 |

15 Ave. No. of
16 Customers 355,905

17 Degree Day Variance: (Positive = Warmer Than Normal) (392)

18 Normal Average Use per customer 1,496.1 kWh per month 17,953.6 kWh per year

| 19 | Base Load | Customers | kWh Sales |
|---|---|---|---|
| 20 | Oct | 355,644 | 337,632,216 |
| 21 | Total | 355,644 | 337,632,216 |

22 Base Load (kWh) Per Customer (BL): 949.4

OTS Exhibit No. 3
Schedule 7
Revised August 2004

OTS Exhibit No. 3
Schedule 8
**Revised August 2004**

**PPL Electric Utilities Corporation**
**Docket R-00049255**
**Present Rate Revenue - Residential Customers**
**per OTS**

| | Heating | Per Company | OTS Proposed Adjustment | OTS Recommended |
|---|---|---|---|---|
| | (A) | (B) | (C) | (D) |
| 1 | Heating Customer Bills | 4,487,117 (a) | 0 | 4,487,117 |
| 2 | Average Usage Per Customer | 1,450 (b) | 47 | 1,496 (f) |
| 3 | Heating Sales | 6,504,434,124 (c) | 208,879,677 | 6,713,313,801 |
| 4 | Weighted Customer Charge | $6.66 (d) | | $6.66 |
| 5 | Customer Charge Revenue (Line 1 Times line 4) | $29,879,216 | $0 | $29,879,216 |
| 6 | Average Price per kWh (Line 7 Divided by Line 3) | $0.01467 | | $0.01467 |
| 7 | Total Kwh Revenue (Line 3 Times line 6) | $95,449,283 (e) | $3,065,204 | 98,514,487 |
| 8 | **Total Heating Revenue** (Line 5 Plus Line 7) | **$125,328,500** | **$3,065,204** | **$128,393,703** |

*Sources:*

(a) OTS Exhibit No. 3, Schedule 5, Page 1, Column E, Line 24
(b) Column B, Line 3 Divided by Line 1
(c) OTS Exhibit No. 3, Schedule 5, Page 3, Column D, Line 9
(d) OTS Exhibit No. 3, Schedule 5, Page 2, Column D, Line 20
(e) OTS Exhibit No. 3, Schedule 5, Page 3, Column E, Line 16
(f) OTS Exhibit No. 3, Schedule 7, Column D, Line 18

OCA Statement No. 2
8/10/04 Hbg FX

DOCUMENT

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) | DOCKET NO. R-00049255 |

DOCKETED

AUG 18 2004

DIRECT TESTIMONY

OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 2004

RECEIVED

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PA PUC
SECRETARY'S BUREAU

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

TABLE OF CONTENTS

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) ) | DOCKET NO. R-00049255 |

Direct Testimony of Thomas S. Catlin

**Qualifications**

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

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

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

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

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

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. (CDM). Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My

project administration responsibilities included budget preparation as well as labor and cost monitoring and forecasting. As a member of CDM's Management Consulting Division, I performed cost of service, rate, and financial studies involving approximately 15 municipal and private water, wastewater, and storm drainage utilities. These projects included: determining total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; preparing bill analyses; developing cost and revenue projections; and preparing rate filings and expert testimony.

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

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

A. Yes. I have previously presented testimony on more than 200 occasions before the Federal Energy Regulatory Commission and the public utility commissions of Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio,

Oklahoma, Rhode Island, Utah, Virginia, and West Virginia, as well as before this Commission. I have also filed rate case evidence by affidavit with the Connecticut Department of Public Utility Control.

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

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

## Purpose and Summary

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter Associates was retained by the OCA to assist in the evaluation of the filing made by PPL Electric Utilities Corporation (PPL Electric, or the Company) for rate relief. In this testimony, I address certain policy and revenue requirement issues. My associate, Mr. Lafayette K. Morgan presents the OCA's overall recommendation with regard to the revenue increase which the Company should be authorized in this proceeding. In developing his recommendation on behalf of the OCA, Mr. Morgan has incorporated my findings as well as the rate of return recommendation of Mr. Matthew I. Kahal and the recommendations of Mr. Roger Colton regarding social program costs.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. A summary of my findings and recommendations is as follows:

- PPL Electric's proposal to implement a Distribution System Improvement Charge (DSIC) must be rejected not only because Counsel advises me that it is not permitted under the Pennsylvania Public Utility Code, but also because it would constitute improper single issue ratemaking. The DSIC would guarantee annual rate increases by considering certain cost increases while ignoring offsetting cost savings. In addition, other issues and problems make the DSIC contrary to sound ratemaking principles.

- The proposal to amortize the deferred expenses incurred in 2003 related to Hurricane Isabel must be denied because Counsel advises me that allowing recovery would constitute a de facto rate cap exception in violation of the Electric Competition Act and the Settlement in PPL Electric's Restructuring Proceeding at

Docket No. R-00973954. In addition, the costs which PPL deferred include costs which were not incremental and should not be eligible for deferral and recovery.

- PPL Electric's proposal to amortize the one-time employee displacement costs recorded in 2003 in conjunction with its Automated Meter Reading (AMR) program should also be denied. Counsel advises me that, like deferred Hurricane Isabel expenses, allowing the amortization of these costs in rates would constitute a de facto rate cap exception. Moreover, inclusion of those costs in rates would result in the costs of the AMR program to ratepayers exceeding the benefits.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into sections corresponding to each of the issues summarized above. These sections are set forth in the Table of Contents for this testimony.

## Distribution System Improvement Charge

Q. PLEASE SUMMARIZE PPL ELECTRIC'S PROPOSED DISTRIBUTION SYSTEM IMPROVEMENT CHARGE.

A. PPL Electric is proposing to implement a Distribution System Improvement Charge (DSIC) to provide for the recovery of the fixed costs of certain improvements to its distribution system between rate cases. Under PPL Electric's proposal, eligible projects would include: replacements of existing facilities that have worn out, are in deteriorated condition or are required as the result of new regulations; unreimbursed costs of capital projects to relocate facilities due to highway relocations; and security improvements. The fixed costs recovered through the DSIC would include depreciation, a return on investment and income taxes associated with new projects placed in service each year.

The initial charge under DSIC Rider would become effective on January 1, 2006 and would include eligible investment for the period January 1, 2005 through November 30, 2005. The charge would be increased each subsequent January 1st to include

investment in the prior twelve months ended November 30th. The DSIC would be reset to zero at the time of each rate case and would be limited to no more than five percent of PPL Electric's distribution charges. PPL Electric has proposed that the DSIC be subject to annual reconciliation so that any undercollection of eligible costs would be recouped by the Company or any overcollection would be refunded to ratepayers.

Q. DO YOU AGREE WITH PPL ELECTRIC THAT IT SHOULD BE ALLOWED TO IMPLEMENT ITS PROPOSED DISTRIBUTION SYSTEM IMPROVEMENT CHARGE?

A. No. I have identified a number of issues and problems with the proposed DSIC which necessitate its rejection by the Commission. These include:

- The DSIC would constitute improper single issue ratemaking and would provide a means of guaranteeing increases in rates to recognize certain cost increases without recognizing offsetting cost savings.
- Verification of the eligibility of projects for inclusion in the DSIC would be problematic.
- The proposed annual process for establishing the amount of the DSIC surcharge is unrealistic.
- The DSIC would reduce or eliminate certain essential aspects of the review and oversight of PPL Electric's rates.

In addition to these technical issues and problems, Counsel advises me that the DSIC is not permitted under the Pennsylvania Public Utility Code. The legal issues associated with PPL Electric's proposed DSIC will be addressed by Counsel in the OCA's Brief in this proceeding.

Q. WOULD YOU PLEASE EXPLAIN WHY THE DSIC WOULD CONSTITUTE IMPROPER SINGLE ISSUE RATEMAKING?

A. Yes. Under the DSIC, the only changes in costs eligible for consideration would be the depreciation, return and income taxes on certain improvements to the distribution system between rate cases. As a result, the DSIC would serve as a form of an attrition adjustment which would guarantee that rates would increase each year. The DSIC assumes that net distribution plant will increase each year and ignores offsetting cost reductions.

Q. HAS THE COMPANY PROVIDED AN ESTIMATE OF THE AMOUNT OF PLANT WHICH WILL BE ELIGIBLE FOR INCLUSION IN THE DSIC?

A. Yes. According to the response to OCA II-23, PPL Electric estimates that the plant eligible for inclusion in the DSIC will be $27.4 million in 2005, $28.6 million in 2006 and $30.3 million in 2007 – a total of over $86 million in three years. When accumulated depreciation on the eligible plant is deducted, the net distribution plant eligible to earn a return through the DSIC will increase by an average of more than $28 million per year for 2005 through 2007.

Q. IS THIS ASSUMED INCREASE IN NET DISTRIBUTION PLANT APPROPRIATE?

A. No. PPL Electric's proposal effectively assumes that the Company's total net distribution plant will grow by more than the $28 million dollars per year. However, since December 31, 1995 (which roughly corresponds to the end of the future test year in PPL's last rate case on September 30, 1995), net distribution plant has increased by only $13.4 million per year. Moreover, subsequent to restructuring, PPL Electric's net distribution plant has declined, from $1,920.6 million as of January 1, 2000 to $1,861.2 million as of December 31, 2003. This represents a reduction of over $14.8 million per year. This has occurred because depreciation accruals on distribution plant have exceeded distribution plant additions. That is, since restructuring, the capital investment

which PPL Electric has recovered through the depreciation of existing distribution plant has exceeded the amount which the Company has reinvested in its distribution system.

Q. IN ADDITION TO INAPPROPRIATELY ASSUMING THAT THE NET DISTRIBUTION PLANT ELIGIBLE TO EARN A RETURN IS INCREASING BY MORE EACH YEAR THAN THE PLANT TO BE INCLUDED IN THE DSIC, ARE THERE OTHER COST SAVINGS WHICH PPL ELECTRIC HAS FAILED TO RECOGNIZE?

A. Yes. PPL Electric's proposed DSIC ignores several offsets which would cause the charge under the DSIC to be overstated. The offsets include:

- The rate base deduction for accumulated deferred income taxes (ADIT).
- The elimination of depreciation expense on existing plant replaced by DSIC eligible projects.
- The reduction in maintenance costs resulting from the replacement of existing facilities that are worn out or deteriorated.
- The contribution which new customers make to system costs.

Q. PLEASE EXPLAIN EACH OF THESE OFFSETTING FACTORS.

A. In calculating the distribution plant eligible to earn a return under the DSIC, PPL Electric has only proposed to recognize plant additions net of the accumulated depreciation on those plant additions. In addition to the problem discussed previously with regard to the overstatement of net distribution plant growth, the proposed DSIC would overstate the plant eligible to earn a return by ignoring the ADIT associated with the plant included in the DSIC.

Second, in calculating the depreciation expense associated with DSIC eligible plant, PPL Electric has only recognized the depreciation expense on the new plant. This proposal ignores the fact that the rates established in this case include depreciation

accruals on all existing plant. When existing plant is removed from plant in service as a result of being replaced by DSIC eligible projects, depreciation accruals on that plant cease. PPL Electric has failed to account for this reduction in depreciation expense.

Third, as existing facilities deteriorate and wear out, maintenance costs typically increase. In fact, PPL Electric has indicated in response to OCA II-30 and II-31 that maintenance costs are a function of the age of facilities and that maintenance cost are one of the factors which it considers in determining when to replace existing facilities. However, the proposed DSIC gives no consideration to maintenance cost savings.

Finally, while only non-revenue producing distribution plant additions are eligible for inclusion in the proposed DSIC, PPL Electric has ignored the fact that new customers make a contribution toward the recovery of all system costs. By selectively seeking to recover a portion of plant additions, the DSIC ignores the overall relationship between rates and costs.

Q. THE SECOND PROBLEM WHICH YOU IDENTIFIED WITH REGARD TO THE DSIC RELATES TO THE DETERMINATION OF THE ELIGIBILITY OF PROJECTS FOR INCLUSION. WOULD YOU PLEASE EXPLAIN THIS CONCERN?

A. Yes. If implemented, the Company would make the decision as to which distribution construction projects meet the criteria which it is proposing to establish for DSIC eligibility. It would be difficult and time consuming for the Commission Staff, the OCA or any other party to evaluate the purpose of the project and to audit whether or not the criteria for eligibility for inclusion are met. Moreover, some construction projects may meet the eligibility requirements (e.g., replacing a deteriorated facility), but also result in improved or increased system capabilities. Since the costs of projects which increase system capabilities are not eligible for inclusion in the DSIC, it would effectively become

a matter of PPL Electric's discretion as to whether the project is included in the DSIC or not.

It would not be appropriate for the Commission to simply accept the Company's decision as to what projects should be included in the DSIC. Therefore, implementation of the DSIC would require PPL Electric to have in place accounting and information systems to separately track and verify not only the costs of its construction projects and whether they are completed and being used to provide service, but also details as to the purpose of the projects and the basis for eligibility for DSIC inclusion. Without such systems, an auditor would be unable to test the Company's decisions. However, PPL Electric has not established any such systems for examination in this case.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE ANNUAL PROCESS PROPOSED TO ESTABLISH THE AMOUNT OF THE DSIC SURCHARGE IS UNREALISTIC.

A. The Company has proposed to submit its annual DSIC filings on December 1st of each year for implementation on the subsequent January 1st. At the time it submits its filing, PPL Electric will include preliminary revenue and cost reconciliation data for the period ending November 30th. According to the response to OCA II-33, the Company does not anticipate having final prior year reconciliation information until December 12th. Similarly, it is unlikely that final investment data as of November 30th necessary to calculate the DSIC rate for the coming year will be available on December 1st. As a result, it is clear that there will be no opportunity for the OCA, Commission Staff or other interested parties to undertake any meaningful review of PPL Electric's filing or the DSIC rate prior to its proposed implementation on January 1st. Therefore, PPL Electric's proposed filing process is not realistic.

Q. PLEASE EXPLAIN YOUR CONCERN THAT THE PROPOSED DSIC REDUCES THE PROPER OVERSIGHT OF PPL ELECTRIC'S RATES.

A. In addition to the problems and concerns cited above, the DSIC would reduce or eliminate the proper oversight of PPL Electric's rates in several other ways as well. First, PPL Electric has proposed that the return on investment would automatically be revised to reflect changes in the Company's capital structure. This would result in no opportunity to review and challenge the appropriateness of changes in the Company's capital structure.

Second, the DSIC would be a fully reconcilable surcharge. This would provide guaranteed and automatic cost recovery for capital costs under circumstances where it will be difficult at best for other parties and the Commission to evaluate the prudence and reasonableness of the claimed costs.

Finally, the DSIC may significantly extend the period over which the Company is not subject to a full rate review by permitting PPL Electric to increase rates each year for one cost change without considering other offsetting factors.

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT THE PROPOSED DSIC?

A. Yes. As indicated by the above, the costs which the DSIC would recover are part of the normal costs which PPL must incur to provide service to its customers. As such, the costs do not warrant special recovery separate and apart from the other costs included in base rates.

**Hurricane Isabel Costs**

Q. WHAT CLAIM HAS PPL ELECTRIC MADE FOR COSTS RELATED TO HURRICANE ISABEL?

A. PPL Electric is seeking approval to amortize deferred Hurricane Isabel expenses of $15,0121,949 over five years. This results in an annual expense of slightly in excess of $3 million per year. These deferred expenses are in addition to $2.2 million incurred for capital items.

Q. DID PPL ELECTRIC SEEK APPROVAL TO DEFER THESE EXPENSES?

A. Yes. PPL Electric requested approval to defer Hurricane Isabel expenses in Docket No. P-00032069. In its January 16, 2004 Opinion and Order in that docket, the Commission authorized PPL Electric to defer its costs for accounting and financial reporting purposes subject to the following conditions: *such* approval was not an assurance of future rate recovery of those costs; the approval of deferred accounting treatment of such costs does not include amortization of the losses for ratemaking purposes; and that the issue of PPL Electric's right to recovery shall be decided in PPL Electric's next general rate case (i.e., this proceeding). (Order at pp. 6-7.)

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO PPL ELECTRIC'S REQUEST?

A. I am recommending that approval of PPL Electric's request to amortize deferred Hurricane Isabel costs be denied. These costs were incurred during 2003, prior to the expiration on December 31, 2004 of the transmission and distribution (T&D) rate cap agreed to in PPL Electric's Restructuring Settlement in Docket No. R-00973954. Counsel advises me that allowing these costs, which were incurred during the rate cap period, to be recovered subsequent to the expiration of the rate cap would constitute a de facto rate cap exception in violation of the Electricity Generation Customer Choice and Competition Act (the Act) and PPL Electric's Restructuring Settlement. Counsel also advises me that the basis for this position will be set forth in detail in the brief in this proceeding.

Q. DO YOU AGREE THAT THE FULL $15,011,949 WHICH PPL DEFERRED WOULD EVEN BE ELIGIBLE FOR RECOVERY?

A. No. A significant portion of the $15 million of expenses which PPL Electric deferred for Hurricane Isabel were for regular and overtime salaries and wages and the related benefits. At a minimum, the regular salaries, wages and benefits would have been incurred regardless of whether or not Hurricane Isabel occurred. As such, these costs were not incremental costs which would be eligible for deferral and recovery in rates even if the rate cap did not exist. In addition, some portion of the overtime may also have been incurred in the absence of Hurricane Isabel and would not qualify as incremental costs eligible for deferral.

Q. WHAT IS THE EFFECT OF DISALLOWING PPL ELECTRIC'S CLAIM FOR THE AMORTIZATION OF HURRICANE ISABEL COSTS?

A. As shown on Schedule LKM-9 accompanying Mr. Morgan's testimony, the effect of eliminating the amortization of Hurricane Isabel costs is to reduce future test year expenses by $3,002,000 and to increase net income before taxes by $1,756,000.

**AMR Displacement Costs**

Q. WHAT CLAIM HAS PPL ELECTRIC MADE WITH REGARD TO AMR DISPLACEMENT COSTS?

A. In September 2003, PPL Electric recorded a charge of $8,818,000 for the estimated costs of enhanced benefits for 94 employees being displaced in conjunction with the Company's Automated Meter Reading (AMR) program. This $8,818,000 charge is referred to as a pension termination benefit charge which was accrued under Statement of Financial Accounting Standards No. 88 (SFAS 88). PPL Electric is requesting approval

to amortize this charge over five years and to recover the amortization expense of $1,764,000 in rates.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO PPL ELECTRIC'S REQUEST?

A. I am recommending that PPL Electric not be allowed to recover the $8,818,000 pension termination benefit charge from ratepayers. As with Hurricane Isabel expenses, these costs were incurred prior to the expiration of PPL Electric's T&D rate cap. Counsel advises me that allowing these costs to be amortized and recovered subsequent to the rate cap would constitute a de facto rate cap exception in violation of the Act and PPL Electric's Restructuring Settlement.

Q. WILL RATEPAYERS RECEIVE COST SAVINGS AS THE RESULT OF THE AMR PROGRAM?

A. According to the response to OCA III-8, the net present worth of the benefits of the AMR program are expected to be $202 million and the net present value of the costs are $197 million. Hence, PPL Electric has identified a net benefit of the program of $5 million dollars over the next 15 years. However, in calculating these net benefits, PPL Electric did not include the one-time pension benefit termination charge. The net present value of those one-time costs based on the Company's proposal to amortize them over five years with no return is approximately $7 million dollars. Hence, allowing PPL Electric to amortize the pension benefit termination charge in rates would result in ratepayers bearing costs which exceed the benefits of the AMR program. That is, ratepayers would be better off without AMR if the amortization of the $8,818,000 was allowed.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO THE AMR DISPLACEMENT COSTS WHICH PPL IS SEEKING TO RECOVER?

A. Yes. First, I would like to note that the $8,818,000, pension termination benefit charge was an expense accrual and did not require a cash outlay by PPL. Depending on the performance of the pension trust fund, it is possible that PPL Electric may never be required to make a cash contribution to fund this expense.

Second, I would like to note that the OCA's position that recovery of the pension termination benefit charge be denied will have no effect on PPL's displaced employees. The termination benefits to those employees have already been assured and will be paid from the pension trust fund. As noted above, PPL Electric was not required to make a contribution to the trust to fund these benefits.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION ON PPL ELECTRIC'S COST OF SERVICE?

A. As shown on Schedule LKM-8 accompanying Mr. Morgan's testimony, this adjustment reduces future test year expenses by $1,764,000 and increases net income after income taxes by $1,032,000.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PENNSYLVANIA PUBLIC UTILITY COMMISSION | ) | |
| v. | ) | DOCKET NO. R-00049255 |
| PPL ELECTRIC UTILITIES CORPORATION | ) | |

**AFFIDAVIT**

Thomas S. Catlin being first duly sworn, deposes and says that he is the same Thomas S. Catlin whose Direct Testimony accompanies this affidavit; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Thomas S. Catlin

**Thomas S. Catlin**

Subscribed and sworn before me on this 10 day of August, 2004.

Notary Public

My Commission Expires: 2/2007

DOCUMENT

OCA Statement No. 2-S
8/10/04 Hby FX

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) | DOCKET NO. R-00049255 |

SURREBUTTAL TESTIMONY

OF

THOMAS S. CATLIN



ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE



AUGUST 2004

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) ) | DOCKET NO. R-00049255 |

Surrebuttal Testimony of Thomas S. Catlin

**Qualifications**

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

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of the Pennsylvania Office of Consumer Advocate (OCA) which has been identified as OCA Statement No. 2. My qualifications and experience are set forth in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to certain arguments presented in the rebuttal testimony submitted on behalf of PPL Electric Utilities Corporation (PPL Electric or the Company). In particular, I will address Mr. Krall's rebuttal testimony with regard to the proposed distribution System Improvement Charge (DSIC) and the recovery of Hurricane Isabel costs. I will also respond to Mr. Schadt's rebuttal testimony with regard to Automated Meter Reading costs.

**Distribution System Improvement Charge**

Q. WHAT RESPONSE DO YOU HAVE WITH REGARD TO MR. KRALL'S REBUTTAL TESTIMONY PERTAINING TO THE PROPOSED DSIC?

A. First, I would like to respond to Mr. Krall's argument at page 3 of his rebuttal testimony that without the DSIC, PPL Electric will be unable to collect any money from ratepayers to support the distribution facilities until they are recognized in rate base and that this situation could go on for years. In response, I would note that the appropriate forum for PPL Electric to recover the costs of its distribution system improvements is through a base rate case, where all aspects of its operations can be evaluated. In that way, a determination can be made whether revenue growth and/or other cost savings offset the need for automatic rate increases to recover distribution system investments. Moreover, PPL can file for base rate recognition of distribution system improvements costs when it determines it to be necessary. There is a no need for the lack of rate recognition to go on for years.

Second, I would like to respond to Mr. Krall's claim at pages 12-13 of his rebuttal testimony that depreciation on existing plant does not decline when it is replaced. Mr. Krall argues this is the case because net plant does not change as the result of the retirement of existing plant and depreciation is calculated by applying the accrual rate to net plant. This argument is not accurate. As can be seen from page III-4 of the depreciation study filed by PPL Electric in this proceeding (Exhibit JJS-1), depreciation expense accruals are equal to the proposed depreciation rates multiplied by gross plant in service, not net plant. Hence, when existing plant is replaced and retired, depreciation expense accruals on that plant cease.

## Hurricane Isabel and AMR Costs

Q. WHAT RESPONSE DO YOU HAVE TO THE REBUTTAL TESTIMONY OF MR. KRALL AND MR. SCHADT WITH REGARD TO HURRICANE ISABEL AND AMR COSTS?

A. At pages 37 -38 of his rebuttal testimony, Mr. Krall argues that recovery of Hurricane Isabel costs deferred in 2003 does not constitute a rate cap violation because the Competition Act only capped rates through 2004 and PPL is not seeking recovery until 2005. Mr. Schadt has made a similar argument with regard to pension benefit termination charges associated with the AMR program that were incurred in 2003 at page 6 of his rebuttal testimony. As will be addressed in more detail in the OCA's brief, Counsel advises me that these costs are not eligible for recovery subsequent to the expiration of the rate cap because they were incurred at the time the rate cap was in effect through the Restructuring Settlement. Allowing recovery beginning in 2005 is effectively the same as having allowed an exception to the rate cap to permit recovery in 2003 or 2004.

## Summary

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO PPL'S REBUTTAL TESTIMONY?

A. Yes. Mr. Krall and Mr. Schadt have raised certain other arguments with regard to my testimony on the DSIC and recovery of Hurricane Isabel and AMR pension benefit termination charges to which I have not responded. These arguments have either been previously addressed by me or are policy-oriented or legal in nature. I would simply like to note that a lack of a response is not intended to indicate agreement or acceptance of those arguments.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PENNSYLVANIA PUBLIC UTILITY COMMISSION | ) | |
| v. | ) | DOCKET NO. R-00049255 |
| PPL ELECTRIC UTILITIES CORPORATION | ) | |

**AFFIDAVIT**

Thomas S. Catlin being first duly sworn, deposes and says that he is the same Thomas S. Catlin whose Surrebuttal Testimony accompanies this affidavit; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Thomas S. Catlin

Subscribed and sworn before me on this 10 day of August, 2004.

Notary Public

My Commission Expires: 2/2007

OCA STATEMENT NO. 3

H.bg ✓ 8/10/04

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) | DOCKET NO. R-00049255 |





DIRECT TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 2004

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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**DIRECT TESTIMONY OF MATTHEW I. KAHAL**

## I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this case by the Exeter Associates, Inc., an economic consulting firm. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 25 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001 I was employed at that firm as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the

focus of much of my professional work has shifted to electric utility restructuring, power supply markets and competition.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College teaching courses on economic principles, development economics and business.

A complete description of my professional background is provided in Appendix A

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before approximately two- dozen state and federal utility commissions in more than 250 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. In 1989, I testified before the U.S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found in Appendix A, with my Statement of Qualifications.

Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A. Since 2001, I have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of the Ratepayer Advocate, Rhode Island Division of Public Utilities, Louisiana

Public Service Commission, Arkansas Public Service Commission, Maryland Department of Natural Resources and Energy Administration, and MCI.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified on cost of capital and other matters before this Commission in gas, water, telecom and electric cases during the past 20 years. A listing of those cases is provided in my attached Statement of Qualifications, Appendix A.

## II. OVERVIEW

### A. Recommendation and Summary

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

A. I have been asked by the Office of Consumer Advocate (OCA) to develop a recommendation concerning the fair rate of return for PPL Electric Utilities Corporation (PPLEU or the Company) for its jurisdictional distribution service rate base. This includes a determination of the appropriate capital structure percentages and the cost rates for debt, preferred stock and common equity. In that regard, I have conducted an independent cost of equity study.

Q. WHAT IS THE COMPANY'S RATE OF RETURN PROPOSAL IN THIS CASE?

A. Company witness and outside expert, Mr. Paul R. Moul, sponsors the Company's rate of return proposal in this case. Mr. Moul recommends a return on rate base of 8.80 percent, including 11.5 percent on the common equity component. His capital structure is based on projected capitalization at December 31, 2004 and includes 46.87 percent common equity.

Q. IS MR. MOUL'S RECOMMENDATION REASONABLE?

A. No, I believe that he has greatly overstated the fair rate of return, particularly the cost of common equity. This is the result of errors and faulty assumptions in his Discounted Cash Flow (DCF) and other cost of capital studies. Moreover, his final recommendation appears to be based on the application of four methods (DCF, risk premium, Capital Asset Pricing Model (CAPM) and comparable earnings) despite this Commission's clear preference for the DCF model. Using the other three methods, Mr. Moul obtains returns significantly higher than his DCF estimate, resulting in his final recommended range of 11.0 to 11.75 percent.

Q. DOES MR. MOUL INCLUDE AN EXPLICIT RATE OF RETURN "BONUS" FOR SERVICE QUALITY?

A. Mr. Moul does not identify or quantify a specific adjustment to rate of return for service quality. However, his recommendation of 11.5 percent slightly exceeds the midpoint of his recommended range (i.e., the midpoint of 11.0 to 11.75 percent is 11.38 percent), and this appears to be related to assertions regarding service quality.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME?

A. As shown on my Schedule MIK-1, at this time I recommend a return on jurisdictional rate base of 7.85 percent, including a return on common equity of 9.50 percent. I have adopted a capital structure and debt/preferred cost rates identical or very similar to what Mr. Moul proposes. My 9.50 percent common equity cost rate is based primarily upon a DCF analysis, although I employ the CAPM as a check on my DCF evidence.

Q. HOW DOES YOUR RECOMMENDATION COMPARE TO THE RETURN ESTABLISHED IN THE COMPANY'S LAST BASE RATE CASE?

A. In the Company's last case, concluded in 1995, this Commission awarded a common equity return of 11.5 percent, the same figure that Mr. Moul recommends in this case, nearly a decade later.

Q. WHY DO YOU BELIEVE A RATE OF RETURN ON EQUITY REDUCTION OF APPROXIMATELY TWO PERCENTAGE POINTS IS APPROPRIATE?

A. I believe that there are several compelling reasons why a substantial rate of return on equity reduction is warranted in this case as compared with 1995. First and foremost, capital market costs generally have declined substantially since the mid 1990s, as shown on my Schedule MIK-2 which displays historic and recent interest rates. In the 1994/1995 time frame, single A utility bond rates were yielding about 8 percent and ten-year Treasury notes at that time were yielding about 6.6 percent. This compares to yields

in 2004 of 6 to 7 percent for utility bonds and 4 to 5 percent for ten-year Treasury notes. I discuss these capital cost trends in more detail below.

A second crucial factor is that the Company has been transformed from being an integrated electric utility, with a high degree of generation asset concentration (in its Susquehanna nuclear station), to a low-risk delivery service company. As Mr. Moul correctly observes, "the rates being considered in this case relate solely to the unbundled delivery service"[1] (page 7). Thus, the Company's change in business profile by itself would warrant a reduction in the authorized return, even if capital costs generally are at the same level as in 1995.

A third reason why a reduction is appropriate pertains to recent changes in the U.S. tax code. In May 2003, Congress enacted modifications to the structure of income taxes that substantially lower the income tax rate on both capital gains and corporate dividends, with the dividend tax reduction being particularly dramatic. Since many investors focus on the after-tax returns they can expect to receive, this tax legislation has the effect of lowering the cost of capital for dividend paying stocks, such as those of utilities. This implies that the cost of equity since 1995 probably has fallen further than the decline in long-term bond yields. The salutary effect of the tax law change should be reflected in the rate of return award in this case.

As a result of all three reasons, a substantial reduction in the rate of return award clearly is warranted in this case, and my 9.5 percent estimate is fully supported. Mr. Moul's proposal to retain the 11.5 percent, despite these important changes in the cost of capital environment, is not reasonable.

Q. YOUR MAIN DIFFERENCE WITH MR. MOUL CONCERNS THE RETURN ON EQUITY. WHAT EXPLAINS THE DIFFERENCE?

[1] The fair return on rate base at issue in this case pertains only to distribution and not transmission.

A. Mr. Moul conducts a DCF study using a proxy group of delivery service electric utilities and a second proxy group of gas utilities. The gas company proxy group clearly is irrelevant to this case and should be disregarded entirely. Mr. Moul's electric company DCF result (i.e., 10.69 percent) is excessive because (a) the assumed growth factor is unrealistically high; and (b) he improperly includes a market/book adder of 0.44 percent. Correcting these two errors would fully reconcile his DCF results with my recommendation

My other analytic disagreement is Mr. Moul's inclusion of a "size" adjustment in his CAPM study (along with the improper market/book adjustment). This adjustment (an increase of 0.82 percent) is in error because (a) the CAPM model simply does not require this "fix"; and (b) more to the point, PPL is simply not a small company. Removing the size (and market to book) adjustment produces a CAPM estimate approximately consistent with my recommendation.

**B. <u>Capital Cost Trends</u>**

Q. YOU HAVE STATED THAT CAPITAL COSTS HAVE DECLINED SINCE THE COMPANY'S LAST RATE CASE. CAN YOU DOCUMENT THAT TREND?

A. Yes. Schedule MIK-2 presents capital cost trend data over the past decade through May 2004. This includes general inflation, short-term (i.e., 3-month) Treasury yields, ten-year Treasury yields and yields on single-A rated utility bonds (Moody's). This schedule shows that capital market cost conditions in 2003 and so far in 2004 are quite favorable compared with past years. Inflation is running at about 2 percent, ten-year Treasury yields are in the 4 to 4.5 percent range and utility bond yields have averaged about 6.5 during the past year. These low interest rates reflect the absence of inflation (and, more

importantly, favorable inflationary expectations) and an accommodative monetary policy conducted by the Federal Reserve Board (Fed).

Q. YOUR SCHEDULE SHOWS THAT LONG-TERM INTEREST RATES ARE QUITE LOW COMPARED TO PAST YEARS. DOES THIS ALSO APPLY TO THE COST OF EQUITY?

A. Yes, I believe so. The factors that cause low long-term interest rates (e.g., favorable inflation conditions, an accommodative Fed, etc.) also favorably affect the cost of equity, and there is no reason to believe this would not apply to PPLEU, as well. There is another factor that favorably affects the cost of equity but does not have a similar beneficial effect on bonds – federal tax policy. Last year, Congress enacted tax legislation reducing income tax rates on both capital gains and on common stock dividends. Lower tax rates mean that investors are willing (or should be willing) to accept lower (pre-tax) returns to hold common stocks. I believe my DCF analysis captures these cost of equity reducing tax benefits since it is based on market data from a time period after the enactment of these very favorable tax deductions. Other methods, such as Mr. Moul's long-term historic risk premium studies, would fail to capture the effects of this important change.

One of the purposes of the recent tax law changes that lower capital gains and dividend income taxes is to lower the corporate cost of capital, and I believe that this legislation has succeeded in doing so. Thus, to the extent that the stock pays dividends and is held by the investor in a taxable account, the tax law change has lowered the investor's return requirement. As an analogy, one need only look at the relatively low interest rates on tax-exempt bonds, as compared with fully taxable bonds.

Q. WHAT IS THE CURRENT TREND AND NEAR-TERM OUTLOOK FOR CAPITAL COSTS?

A. During the past year, capital costs (and inflation) have been very low and generally declining, reaching a low point in late March or early April of this year. For example, by the end of March, utility bond yields had declined below 6 percent, and long-term Treasury yields had reached as low as about 4.5 percent. However, in the past two months long-term yields have moved sharply upward as of this writing (in mid June) are more reflective of 2003 averages. This upward trend reflects the recognition by markets that the economic recovery is moving ahead briskly and labor markets tightening. The recent gains in employment may provide a basis for Federal Reserve monetary tightening, which markets now expect to occur. Despite the sudden increases, interest rates remain quite low by historical standards.

According to the Blue Chip Economic Indicators "Consensus" forecast (May 10, 2004), yields on ten-year Treasury notes are expected to increase from current levels of about 4.7 percent to 5.2 percent in calendar 2005. Inflation in 2005 is expected to remain under control, a mere 1.7 percent as measured by the GDP deflator and 2.1 percent as measured by the Consumer Price Index.[2] This outlook is the average of approximately 40 major forecast organizations surveyed by Blue Chip.

Q. DOES YOUR RECOMMENDATION IN THIS CASE REFLECT THAT OUTLOOK?

A. Yes, I believe so. I have attempted to use reasonably recent stock market data and investor analyst earning forecasts. However, in recognition of the recent interest rate increases, I am recommending an award at the upper end of my DCF range, rather than the midpoint of that range.

[2] It should be noted that the May 2004 Consumer Price Index (CPI) is 3.1 percent compared to May 2003. However, this upsurge is largely associated with energy and food. The widely followed "core" CPI for May 2004 is up only 1.7 percent over May 2003.

C. **Organization of Testimony**

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III summarizes my recommendation concerning capital structure and debt/preferred costs. This section also discusses PPLEU's risk profile and credit quality outlook, and presents my disagreements on these issues with Company witnesses Moul and Cannell.

Section IV presents my DCF study, which is the basis of my recommended ROE. I have conducted a DCF study using my preferred proxy group of "delivery service" electric utilities. I reject Mr. Moul's gas utility proxy group since I believe that group to be inappropriate as a risk proxy for PPLEU's electric operations. In addition, Section IV presents a CAPM study which I employ as a check on my DCF results. This responds to Mr. Moul's concern that multiple cost of equity methods should be used in order to provide confidence in the results.

My final section is a critique of the cost of equity studies and methods employed by Mr. Moul in deriving his 11.50 percent ROE recommendation. I would add that one of Mr. Moul's methods is "comparable earnings," which is not a cost of equity method at all, and therefore is inconsistent with cost-based regulation.

## III. CAPITAL STRUCTURE AND INVESTMENT RISK

### A. Capital Structure Recommendation

Q. HOW HAS MR. MOUL DEVELOPED HIS CAPITAL STRUCTURE RECOMMENDATION?

A. He has developed his proposed capital structure and embedded debt/preferred cost rates using capitalization date projected as of December 31, 2004. According to his Schedule 1 (Exhibit PRM-1), he estimates 2004 year-end capital structure for PPLEU as 51.3 percent long-term debt, 1.83 percent preferred stock and 46.87 percent common equity.

Q. HAS HE INCLUDED SHORT-TERM DEBT?

A. No, it appears that he has excluded it as a matter of policy.

Q. DO YOU AGREE THAT IS APPROPRIATE TO EXCLUDE SHORT-TERM DEBT?

A. As a general matter, short-term debt should not be excluded from ratemaking capital structure because it helps to finance a company's used and useful investment in utility assets. Since short-term debt typically is less expensive (on an income tax adjusted basis) than a utility's overall cost of capital, its exclusion may artificially inflate rate of return and thereby overcharge ratepayers. Moreover, the presence of short-term debt affects a company's credit rating and market-determined capital costs. In other words, since ratepayers incur the cost of short-term debt (i.e., when the utility's overall capital costs are reflected in rates), they should receive the benefits as well.

In the case of PPLEU, however, data responses indicate only very modest and intermittent use of short-term debt by PPLEU. The Company employed short-term debt in only six months out of the past 28 months (response to OCA I-3). For the 28 months (January 2002 – April 2004), the average short-term debt balance was approximately $10 million, compared with AFUDC-bearing construction-work-in-progress averaging about

$30 million. Based on these data, it would be reasonable to exclude short-term debt from capital structure as long as the short-term debt instead is used in the calculation of the Company's AFUDC rate. This will ensure that customers receive the full benefit of short-term debt.

Q. WHAT ADJUSTMENTS HAS MR. MOUL MADE TO THE ACTUAL CAPITAL STRUCTURE TO DERIVE HIS 12/31/04 PROJECTED RATEMAKING CAPITAL STRUCTURE?

A. He has made several adjustments to the actual 12/31/03 PPLEU capitalization:

1. He has reflected the long-term debt redemptions scheduled to take place during 2004. Since no new long-term debt is included, I must assume that these redemptions will be financed through internally generated cash. The redemptions total approximately $130 million.

2. Mr. Moul incorporates an assumed $15 million in retained earnings accumulation in 2004 (i.e., earnings minus dividend payments to the parent).

3. Transition bonds (supporting the approved stranded costs) are excluded from capital structure since that debt does not finance delivery service rate base.

4. The debt and preferred stock outstanding balances are reduced by the unamortized balance of call premiums. In the case of long-term debt, this is an adjustment of about $27 million.

Q. DO YOU AGREE WITH THESE ADJUSTMENTS?

A. I agree with two of the adjustments but disagree with the other two. First, I agree that Transition debt should not be included in the delivery service ratemaking capital structure. It does not support rate base, and its inclusion would constitute double counting. This debt totals approximately $1.4 billion, so its exclusion is a very large adjustment. Second, at this time I agree that the scheduled redemptions of $130 million of long-term debt also should be excluded since it will not be available to finance rate base at the conclusion of this case. The redemptions are scheduled for the first half of

this year, and therefore the Company should be able to verify that (a) the exemptions actually occurred; and (b) no new long-term debt was issued to finance the redemptions.

Q. WHAT ARE YOUR DISAGREEMENTS?

A. I believe it is improper to adjust the capital structure for the unamortized balance of call premiums, although I do not object to the recovery of those costs as part of the embedded cost of debt, as Mr. Moul has done. This capital structure adjustment serves to artificially decrease the debt ratio and therefore inflate the overall rate of return. However, the Commission accepted this capital structure treatment in the Company's 1995 rate case, and for that reason I have not proposed reversing Mr. Moul's adjustment in this case.

I also object to Mr. Moul's proposal to increase the retained earnings balance in 2004 by $15 million. Although this is not a large adjustment, it is speculative at best and contradicted by recent past practice. Company response to OCA I-13 provides the supporting analysis for this adjustment. That analysis assumed earnings for common equity in 2004 of $43 million and dividend payments to the parent of $28 million.

The Company's own cash flow statements show the projected retained earnings accumulation for 2004 to be unrealistic. In 2003, PPLEU earnings were $25 million compared to dividend payments of $29 million, and in 2002, earnings were $39 million compared with dividend payments of $63 million. Hence, retained earnings actually declined during both of the last two years. There is no convincing basis to accept the proposed 2004 retained earnings increase, and I have reversed that adjustment. Instead, I have adopted the reported actual common equity balance at year-end 2003.

Q. WHAT IS YOUR CAPITAL STRUCTURE PROPOSAL AT THIS TIME?

A. As shown on Schedule MIK-1, I am recommending at this time a long-term debt ratio of 51.59 percent, a preferred stock ratio of 1.85 percent and a common equity ratio of 46.56 percent.

Q. ARE YOU CONTESTING MR. MOUL'S RECOMMENDED COST RATES FOR PREFERRED STOCK OR LONG-TERM DEBT?

A. No, I am not. I accept his calculated year-end cost rates of 6.19 percent for preferred stock and 6.43 percent for long-term debt. These cost rates provide for recovery of call premiums, as well as interest expense and preferred dividends.

Q. HOW DOES YOUR PROPOSED CAPITAL STRUCTURE COMPARE TO THAT OF YOUR ELECTRIC UTILITY PROXY GROUP?

A. Mr. Moul and I use a similar electric utility proxy group. In general, the PPLEU capital structure that I recommend at this time is somewhat stronger than the proxy group average capital structure. I further would note that PPLEU's capital structure is significantly stronger than the PPL Corporation consolidated capital structure. Even after removal of the Transition debt, PPL Corporation's equity ratio is only 33 percent, as of year-end 2003.

**B. <u>Risk Review of PPLEU</u>**

Q. HAS THE COMPANY SPONSORED TESTIMONY DISCUSSING ITS INVESTMENT RISK AND FINANCIAL NEED?

A. Yes. PPLEU has sponsored the testimony of Julie M. Cannell, an outside consultant, as well as Mr. Moul, to discuss issues of investment risk and financial need for PPLEU. Their testimonies address the electric utility industry in general, but also make some points specific to electric delivery service and PPLEU. A central theme in Ms. Cannell's testimony is her assertion that industry risks have increased in recent years.

Q. WHAT INVESTMENT RISKS DOES MS. CANNELL IDENTIFY FOR PPLEU?

A. Her testimony emphasizes several risk areas for PPLEU.

- Uncertainties regarding RTOs and transmission policies;

- PPLEU's provider of last resort (POLR) service obligations, the rights of returning customers, uncertainty over cost recovery for providing this service and related issues.

- As a delivery service-only company, PPLEU's narrow focus and lack of diversification increase its risk.

- The "bypass" threat (including distributed generation) and competitive issues generally.

Mr. Moul echoes these arguments and identifies some additional risks.

Q. ARE ANY OF THE RISK ISSUES DISCUSSED BY MS. CANNELL SPECIFIC TO PPLEU?

A. No, these arguments probably could apply to almost any delivery service electric utility operating in a retail access environment. In fact, that is part of the problem. I see nothing in her testimony specifically on point for PPLEU.

Q. DO YOU SHARE HER CONCERN REGARDING RTO AND TRANSMISSION UNCERTAINTY?

A. No. It is not clear to me why she believes RTO/transmission policy is so problematic or is a risk for PPLEU that should be highlighted. PPLEU is a member of the PJM RTO, which is widely regarded by both the industry and its regulators as the most successful RTO in the United States. Moreover, this rate case addresses distribution service, and we are not addressing the cost of capital for the Company's transmission investment. I find Mr. Moul's comments on this issue (and Standard Market Design) equally puzzling and unrelated to distribution service.

Q. HAS THE COMPANY'S TRANSFORMATION INTO A DELIVERY SERVICE UTILITY CREATED AN ASSET CONCENTRATION OR "SINGLE LINE OF BUSINESS" PROBLEM?

A. No, that argument is farfetched. An asset concentration problem exists when a large percentage of a company's total investment is tied up in a single asset or asset group. An excellent example of such concentration is the Company's former ownership of the Susquehanna nuclear plant. A delivery service company does not have such a problem because no single asset accounts for a large percentage of its total investment. With respect to the asset concentration problem, PPLEU is much less risky than the former vertically-integrated PP&L.

Ms. Cannell also argues that the delivery service utility is more vulnerable to an economic down turn than the integrated utility because the integrated utility can partially compensate by selling power into the wholesale market. The implication is that the wholesale sales opportunity provides greater net revenue stability for the integrated utility than achievable by a distribution utility.

This wholesale market diversity argument is very unpersuasive, and neither Ms. Cannell nor Mr. Moul provides any empirical support for their assertions. Economic fluctuations do occur and create (between rate cases) risk for both integrated and delivery service utilities. However, the integrated utility cannot insulate itself from this risk through wholesale sales. First, if the local service area experiences a downturn, the regional wholesale market is likely to as well. It is unreasonable to assume that the wholesale market will be unchanged during an economic downturn. Second, as a short-term solution to economic fluctuations, sales into the wholesale market will not prop up earnings. This is because margins on such short-term sales (under the fully regulated, vertically integrated paradigm) are returned to ratepayers, not retained for shareholders.

It is true that earnings on long-term sales often can be retained by shareholders, with PP&L's sale of 130 MW of the Susquehanna nuclear plant to BG&E in the mid 1980s serving as an example. Such long-term capacity sales are the result of utility

having long-term excess capacity -- not short-term economic fluctuations -- and may result in the integrated utility failing to cover its total costs on the capacity sold into the wholesale market.

The so-called "diversity benefit" does not make integrated utilities less risky than the narrower delivery service utilities. The exact opposite is true.

Q. WHY IS THE DELIVERY SERVICE UTILITY LESS RISKY?

A. I have already mentioned the asset concentration and excess capacity problems that sometimes afflict generation but are absent from the distribution function. The other issue is competitiveness and revenue stability. While economic fluctuations and competitive pressures can affect a utility's ability to retain its industrial load, there is simply no evidence that non-industrial customers relocate in response to regional differences in electric rates. Mr. Moul notes:

> Energy deliveries to non-residential customers which represent 64% of the Company's energy deliveries are usually thought to be of higher risk than to residential customers. (Page 9)

This observation regarding industrial customers might be accurate for an integrated utility, but it overstates the risk for a distribution utility. This is because, all else equal, industrial customers account for a much smaller percentage of distribution revenue than they do of the total revenue of an integrated company. By the same token, residential service (believed to be more stable) will be a much larger percentage of a distribution utility's total revenue than that of the integrated utility. Simply put, the loss of industrial load is a much smaller threat to the distribution utility.

Q. HAVE YOU EXAMINED PPLEU'S DEPENDENCE ON INDUSTRIAL DISTRIBUTION REVENUE?

A. Yes. Prior to restructuring, industrial sales accounted for about 20 to 25 percent of the Company's total revenue. Distribution revenue, however, is a sharply lower percentage with the reduction depending on the definition of "industrial." For example, industrial loads served at 69 kV and above account for less than one percent of PPLEU's distribution revenue at current rates. Using a more liberal definition (i.e., 12 kV and above), the large customers provide about six percent of distribution revenue.

Q. IS DISTRIBUTED GENERATION OR SELF GENERATION A SIGNIFICANT THREAT TO PPLEU'S FINANCIAL WELL BEING?

A. Both Mr. Moul and Ms. Cannell mention this issue but present no evidence that it either has been or is expected to be a significant problem for PPLEU. If anything, self-generation "bypass" is probably a bigger threat to the integrated utility for the reason mentioned above, i.e., industrial distribution service revenues are very small.

Q. MS. CANNELL SEEMS TO BELIEVE THAT POLR SERVICE POSES A SIGNIFICANT RISK FOR PPLEU. DO YOU AGREE?

A. No. Her testimony fails to recognize PPLEU's current low-risk arrangements for POLR service. The Company has arranged a long-term wholesale "full requirements" supply contract at fixed prices with its corporate affiliate, PPL EnergyPlus, through the remainder of this decade. This arrangement addresses all of the concerns raised in Ms. Cannell's testimony regarding supply adequacy, price stability, and rate recovery -- unless she believes PPLEU's own corporate affiliate will default on its contractual obligations. This arrangement is viewed very favorable in the financial community, as noted by credit rating agencies.

> Standard & Poor's considers PPLEU's competitive position as above average, because of the long-term contractual agreement with PPL Energy Plus that transfers all price and volume risks to PPL. (August 29, 2003, response to OCA 1-5)

Similarly, Moody's report of February 24, 2004 notes that, "Supply and price risk is virtually eliminated by its Provider of Last Resort or all requirements contract through December 31, 2009."

Q. COULD POLR OBLIGATIONS BE A SIGNIFICANT RISK AFTER 2009?

A. It is possible but not very likely. Other distribution utilities not as fortunate as PPLEU (including those in my and Mr. Moul's proxy groups) have implemented procurement plans for POLR supply without incurring significant risk exposure. Moreover, if POLR service does impose risk on the utility, such risk should be reflected in the POLR rates, not the distribution rates.

Q. DOES MR. MOUL IDENTIFY ANY ADDITIONAL RISKS?

A. He states that as a delivery service utility PPLEU reflects the loss of "economies of scope, control over planning and operation of both generation and delivery of electricity, and more diversified sources of revenue." (page 9) However, Mr. Moul never explains what any of this has to do with PPLEU's investment risk.

While I agree with Mr. Moul that an integrated utility jointly plans generation and delivery, and I agree that there exist certain efficiencies associated with vertical integration, there are, of course, also certain efficiencies from using the competitive market. I also cannot agree with his assertion that the integrated utility has "diversified sources of revenue." The vertically-integrated utility is mostly in the business of selling a single, bundled product – delivered, end-use electricity. Diversification can be achieved, of course, but only by entering into other, non-regulated (typically riskier) lines of business.

Q. DO CREDIT RATING AGENCIES VIEW PPLEU AS RISKY?

A. No. FitchRating (July 11, 2003) states that its "ratings reflect the low-risk nature of the company's regulated distribution operations and the absence of any near-term liquidity

concerns." Moody's (February 24, 2004) mentions that PPLEU's credit strengths are attributable to a "lower business risk profile as a regulated transmission and distribution utility." Standard & Poor's A- rating is attributable to "its low-risk transmission and distribution (T&D) electric operations, a large and stable residential and commercial customer base (78%), and a long-term power supply contract (that runs from 2001 to 2009)." S&P goes on to state that "ring-fencing" helps to insulate PPLEU from unregulated risk but this insulation is not complete.

Q. BOTH MR. MOUL AND MS. CANNELL NOTE THE IMPORTANCE OF PPLEU'S CREDIT RATING AND THE NEED TO ACHIEVE ACCEPTABLE FINANCIAL RESULTS. WHAT DO THEY EMPHASIZE?

A. Ms. Cannell cites an S&P report that mentions the need for PPLEU to achieve cash flow coverages of 3.0 to 3.1x and a debt ratio of 53 to 55 percent (page 20). She further discusses the need to sustain a reasonable stock price. Mr. Moul discusses credit rating standards for pre-tax interest coverage and the ability of PPLEU to fund its construction program (about $200 million per year).

Q. DO YOU BELIEVE THAT YOUR RECOMMENDATIONS ARE RESPONSIVE TO THESE CONCERNS?

A. Yes, very much so. My rate of return recommendation incorporates a 51.6 percent debt ratio (below the 53 to 55 percent cited by Ms. Cannell) and would provide a pro forma pre-tax interest coverage ratio of 3.3x.

I agree that the ability to fund construction is important, and the Company's cash flow appears adequate in that regard. The construction estimates cited by Mr. Moul appear to be a slight reduction from PPLEU's actual construction outlays in 2002 and 2003.

Although it is difficult to forecast cash flow, the following table shows what PPLEU's cash flow would have been in 2001 through 2003 had the Company actually earned the 9.5 percent on equity that I recommend in this case (i.e., $117 million based on $1.23 billion of common equity.)

PPL Electric Utilities Corporation
Pro Forma Cash Flow Analysis
(Million $)

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Cash Flow from Operations | $528 | $274 | $392 |
| Adjustment to Earnings at 9.5% ROE | +92 | + 78 | (02) |
| Pro Forma Cash Flow from Operations | $620 | $352 | $390 |
| Construction | (235) | (224) | (138) |
| Net Cash Flow | $385 | $128 | $252 |

Source: SEC Form 10K for 2003

Cash flow from operations, adjusted for earnings of $117 million (i.e., 9.5 percent ROE) clearly is strong and can finance construction. Moreover, cash flow coverage appears to be more than sufficient to meet the 3.0 x to 3.1 x standard cited by Ms. Cannell. For example, the pro forma 2003 results, at a 9.5 percent ROE, would provide a cash flow coverage ratio of nearly 4.0x.

Q. SHOULD THE COMMISSION FOCUS ON THE COMPANY'S STOCK PRICE, AS MS. CANNELL SUGGESTS?

A. No, that is not really practical. PPLEU's stock is not traded, and PPL Corporation's stock price is likely to be largely driven by its extensive unregulated and overseas operations, particularly merchant power. There is no need for the Commission to target a

particular stock price for PPL Corporation. Targeting a particular stock price is neither practical nor is it a legitimate rate setting methodology.

## IV. COST OF COMMON EQUITY STUDY

### A. Overview Of Cost Of Equity Study Results

Q. HOW HAVE YOU ESTIMATED PPLEU'S COST OF COMMON EQUITY?

A. I have relied upon an application of the standard discounted cash flow (DCF) model applied to a proxy group of electric utility companies reasonably comparable in risk to PPLEU. This section of my testimony describes the analysis. The DCF analysis is the basis for my recommendation, but I also prepared a capital asset pricing model (CAPM) study as a check on my DCF results.

Q. WHAT DCF STUDY RESULTS DID YOU OBTAIN?

A. My DCF analysis produces a cost of equity range of 8.5 to 9.5 percent, with a midpoint of 9.0 percent. Normally, I would be inclined to recommend the midpoint of my range as the fair return (assuming the utility in question is similar in risk to the proxy group). However, during the past two months interest rates have increased sharply in response to what appears to be a strong economic recovery. Since my study employs six months of historical market data, the six-month average (January-June 2004) may somewhat understate the going forward cost of capital. I therefore recommend the upper end of my DCF range -- 9.5 percent.

Q. SHOULD THE FAIR RATE OF RETURN AWARD BE BASED ON FORECASTS OF INTEREST RATES?

A. While I believe published forecasts of interest rates are useful in understanding trends, it is preferable to base the cost of capital determination on actual market data (averaged over some reasonably recent period of time). Interest rate forecasts typically are based on assumptions and involve therefore some degree of speculation.

Q. DOES YOUR CAPM STUDY CONFIRM THE REASONABLENESS OF YOUR DCF STUDY?

A. Yes, although the CAPM results are somewhat higher than the DCF results. My application of the CAPM produces a return range of approximately 9 to 10 percent.

Q. DOES YOUR DCF STUDY INCLUDE A "LEVERAGE" ADJUSTMENT, AS PROPOSED BY MR. MOUL?

A. No. This adjustment is unnecessary and is improper, and I have not included it in either my DCF or CAPM studies.

Q. HAS MR. MOUL USED THE DCF MODEL?

A. Yes, he has used the DCF in conjunction with other methods (risk premium, CAPM and comparable earnings) in developing his 11.5 percent recommendation. I discuss the problems with his use of these methods in the next section of my testimony.

Mr. Moul has developed proxy groups for purposes of his DCF and CAPM studies, including an electric delivery service proxy group similar to the one that I am using. This is an appropriate procedure. However, he also has elected to use a proxy group of gas utility companies to estimate PPLEU's cost of capital. His use of a proxy group selected from another industry group is both improper and unnecessary.

## B. The DCF Study

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model has been relied upon by this Commission (including in the Company's last rate case), and based on my experience, is the most widely used cost of equity methodology employed by state and federal regulatory commissions. This is a market-based model derived from standard and accepted financial theory. The theory begins by recognizing that any common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows expected by investors. The objective is to identify that discount rate, and this requires an evaluation of investor expectations.

Using certain simplifying assumptions, the DCF formula for dividend paying stocks can be distilled to the following equation:

$K_e = D_0/P_0 (1 + 0.5g) + g$, where:

$D_0$ = the current annualized dividend

$P_0$ = the stock price

$g$ = the long-term dividend per share growth rate

This is referred to as the "constant growth" model, because for mathematical simplicity, it is assumed that the growth rate is constant for an indefinitely long period. While this assumption may be unrealistic in many cases, for traditional utilities (which are far more stable than unregulated companies) the assumption may be reasonable.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and hence valuations) are transparently revealed. Thus, the model cannot be applied to PPLEU, and therefore a proxy is needed. The model could be applied to the ultimate parent, PPL Corporation, but due to the Corporation's extensive unregulated operations, this may lead to an unrealistic estimate of the utility's cost of capital. Mr. Moul and I appear to agree on this point.

I further believe that a properly selected proxy group study is likely to be more reliable than a single company study. This is because there is "noise" or fluctuations in stock price (and other) data that cannot always be readily explained in a simple DCF study. The use of a proxy group helps to allow data anomalies to cancel out in the averaging process.

Q. HOW DID YOU SELECT YOUR PROXY GROUP?

A. My selection recognizes that this case deals with the fair return on the Company's distribution rate base, and proxy companies were selected with that function in mind. I

started with the Value Line Electric Utility "East" data base and selected companies that (a) operate in retail access states; and (b) operate primarily as delivery service electric utilities, i.e., divested most of their formerly regulated generation assets to non-affiliated third parties. The selection of "East" was not intended to be a geographic preference per se. Rather, the "Central" and "West" regions do not have qualifying public-traded delivery service companies in the Value Line database.

As shown on Schedule MIK-4, there are eight such companies, with all but one operating in PJM, the New York Independent System Operator (ISO) or New England ISO. The one exception, Duquesne Light, plans to join PJM by the end of this year.

Schedule MIK-3 also displays certain risk or financial indicators for these companies, including Value Line Safety Rating, bond rating, beta statistic and common equity ratio. Based on its capital structure and bond rating, PPLEU appears to compare favorably with this peer group of Northeast delivery service electric utilities. I believe this is a reasonable proxy group for PPLEU (in terms of investment risk), and that the cost of equity for this group would be an accurate estimate of PPLEU's cost of equity.

Q. ARE THE COMPANIES IN THIS GROUP "PURE PLAY" ELECTRIC DELIVERY SERVICE COMPANIES?

A. Not all. Some continue to own significant amounts of unregulated generation and/or have substantial energy marketing operations (e.g., PEPCO, Northeast Utilities). Hence, these non-regulated risks will affect, at least to a small degree, the estimated cost of capital. However, I believe these companies are viewed by investors as being primarily electric delivery service utilities.

Q. WHAT ELECTRIC UTILITY PROXY GROUP DID MR. MOUL SELECT?

A. Mr. Moul selected a delivery service proxy group similar to mine except that he added two Vermont companies (Central Vermont and Green Mountain) and he deleted United

Illuminating. I did not include the two Vermont companies because Vermont is not a retail access state. Moreover, these two companies are not followed by investment analysts (perhaps due to their small size), and hence financial projections (other than Value Line) are not available for these companies. While I do not object strongly to the inclusion of these two companies, it is not clear that their inclusion materially affects the results.

Q. WHY DID MR. MOUL EXCLUDE UNITED ILLUMINATING (UIL)?

A. UIL is a delivery service electric utility operating in Connecticut and would qualify both for his and my proxy groups. He excluded it because Value Line indicated the possibility that UIL may reduce its dividend (response to OCA I-22). Specifically, Mr. Moul notes that Value Line reports a "split" dividend yield. It should be noted that Value Line's latest report on UIL (June 4, 2004) has discontinued the split dividend, so it now would be appropriate for Mr. Moul to include this company in his proxy electric group.

Q. SHOULD GAS UTILITIES BE USED TO FORM A PROXY GROUP?

A. No, gas utilities are from an entirely different industry with its own unique set of risks and business issues. These companies use a very different technology to provide their service and sell a different product. It would be appropriate to use the gas companies as a cost of capital proxy in this case only if an acceptable proxy group could not be obtained from the industry that PPLEU belongs to -- delivery service electric utility. Fortunately, both Mr. Moul and I have identified such a group, even though our two groups differ slightly. The gas utility proxy group simply is not needed and potentially may provide misleading results.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component ($D_o/P_o$) of the equation. Using the Standard & Poors Stock Guide, I compiled the month

ending dividend yield for each of the eight companies for January through June 2004, the most recent data available to me as of this writing.[3]

I show these data on page 2 of Schedule MIK-4. Over the six-month period, the group average dividend yield ranged from 4.65 percent in March to 5.08 percent in June, averaging 4.86 percent for the six months. This indicates a gradual decline in the dividend yield during the early part of this period followed by an upswing in the last three months. Please note that the dividend yields for the two Vermont utilities are also shown on this schedule. Their inclusion would lower the group average to 4.66 percent. For DCF purposes, I am relying on the 4.86 percent group and six-month average as the starting point.

Q. IS 4.86 PERCENT THE FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend used in the model should be the value the investor expects over the next 12 months. Using the standard "half year" adjustment technique (which I assume to be 2 percent), the DCF adjusted yield is 5.0 percent (i.e., 4.86% x 1.02).

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the growth rate cannot be directly observed but must be inferred through review of available evidence. The growth rate in question is the long-term dividend growth rate, but it is common to use earnings growth as a proxy for dividend growth. This is because, in the long run, earnings are the ultimate source of dividend payments.

One possible approach is to examine historical growth as a guide to investor expected future growth. I have compiled that information on page 5 of Schedule MIK-4

[3] Note that I used June mid-month rather than month ending data to ensure the inclusion of the latest market data. The dividend yields for June will be updated to month ending when available.

for three measures: dividends, earnings and book value per share. However, as this schedule indicates, these historic measures are highly volatile and appear to provide little useful information concerning future long-term growth trends. This is not surprising since all eight companies have gone through a corporate and regulatory restructuring process during this recent five-year period.

Q. WHAT OTHER GROWTH EVIDENCE DID YOU CONSIDER?

A. The DCF growth rate analysis should be prospective, and one particularly useful source of growth rate expectations is the five-year earnings per share projections prepared by securities analysts. There are several public sources that publish projected growth rates, including published surveys of securities analysts.

I provide a listing of four well-known sources of five-year analysts' earnings projections on page 3 of Schedule MIK-4. Three of the four sources, First Call, Zacks and S&P, provide the averages of surveys of securities analysts, while the fourth, Value Line, is based on a single source. For the eight proxy companies, the four sources indicate projected growth ranging from 3.2 percent (First Call) to 3.6 percent (Zacks). However, the UIL growth rate values are unusually low, and excluding that one company (recall that Mr. Moul does so), the projected earnings growth rates increase to approximately 4.0 percent. If the Vermont companies are included, the Value Line growth rates would increase to about 4.3 percent.

Q. WHAT DO YOU CONCLUDE?

A. Based on this evidence, I believe that a reasonable long-run growth rate expectation would be about 3.5 to 4.5 percent. In fact, given the published projections this growth rate range should be viewed as conservatively high.

Q. DO YOU HAVE ANY FURTHER CORROBORATION FOR THE 3.5 TO 4.5 PERCENT RANGE?

A. Yes. Page 4 of Schedule MIK-4 shows growth projections for dividends, book value and retained earnings growth published by Value Line (June 4, 2004). The dividends and book value reflect the next five years, while retained earnings growth is for the time period 2007 to 2009. These measures for the eight proxy companies average 3.0 to 3.7 percent, and absent the very low UIL figures, that group average ranges from 3.4 to 4.1 percent. Again, this confirms the reasonableness of adopting a growth range of 3.5 to 4.5 percent.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. For my electric delivery service proxy group, the dividend yield for the six months ending June 2004 is 4.86% percent and is adjusted forward to 5.0 percent. Adding a DCF growth rate range of 3.5 to 4.5 percent produces an investor expected return of 8.5 to 9.5 percent, with a midpoint of 9.00 percent. Due to the recent upward movement in interest rates, which is not fully reflected in the recent six-month average, I recommend 9.5 percent, or the upper end of my range.

## C. The CAPM Analysis

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach which is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method.

According to this model, the cost of equity ($K_e$) is equal to the yield on a risk-free asset plus a market risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements (or market returns) in the broadly defined stock market. This measures the investment risk that cannot be reduced

or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield on a risk free asset.

The CAPM formula is:

$K_e = R_f + \beta (R_m - R_f)$, where:

$K_e$ = the firm's cost of equity
$R_m$ = the expected return on the overall market
$R_f$ = the yield on the risk free asset
$\beta$ = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable -- the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes betas for each (or most) of the companies that it covers. The difficulty, however, is in the measurement of the market return (and therefore the risk premium), since that variable cannot be directly observed.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term Treasury yield as the risk-free return and the average beta for my eight-company proxy group of delivery service companies. In recent months, long-term Treasury yields have been approximately in the range of 5.0 to 5.5 percent, and the beta for the proxy group (including the Vermont companies) averages 0.69. Finally, and as explained below, I am using a market return of 11 to 12 percent, although the market return at this time might be somewhat lower than that.

Using these data inputs, the CAPM results are shown on page 1 of Schedule MIK-5. My low-end estimate uses a risk-free rate of 5.0 percent and a stock market return of 11.0 percent:

$$K_e = 5.00\% + 0.69\ (11\% - 5\%) = 9.14\%$$

The upper end uses a risk-free rate of 5.5 percent and a stock market return of 12.0 percent.

$$K_e = 5.5\% + 0.69\ (12\% - 5.5\%) = 9.99\%$$

Thus, with these inputs the CAPM provides a return range of 9.1 to 10.0 percent, with a midpoint of 9.6 percent. Although somewhat higher, I believe the CAPM analysis confirms the reasonableness of my DCF analysis and recommendation.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM IS YOUR MARKET RETURN RANGE OF 11 TO 12 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. Various measures of market return are shown on page 2 of Schedule MIK-5, with some measures being more credible than others. These market returns average to about 11.25 percent, and therefore the various risk premium measures average about 6.0 percent.

Q. PLEASE DESCRIBE THESE MEASURES.

A. In general, two approaches have been used to obtain either the risk premium or the market return required by the CAPM. The first is to perform a DCF calculation on the overall stock market, and the second approach makes use of historical realized returns data measured over a long time period. Mr. Moul, for example, uses both approaches, and he obtains an equity risk premium of 5.67 percent (Moul, Direct Testimony, p. 47). His risk premium estimate is certainly within the range of reasonableness.

As shown on page 2 of Schedule MIK-5, the first measure is the market return on the median stock followed by the Value Line Investment Survey. As of late June 11, 2004, Value Line was estimating a stock price "Appreciation Potential" of 50 percent over the next four years, which translates into a 10.67 percent per year stock price

increase. When combined with the median dividend yield of 1.7 percent, as reported by Value Line, the total return is 12.4 percent.

As a general matter, this method is not very reliable because the Value Line "Appreciation Potential" estimates tend to be quite volatile. For example, Mr. Moul uses precisely the same calculation method and Value Line data source (but as of February 2004) and he obtains a total return of 10.48 percent (Moul, Appendix H, page H-4) compared to my 12.4 percent. However, in testimony in another proceeding approximately a year earlier he obtained a Value Line-derived total market return of 17.9 percent. As a result of this volatility and the fact that there is little evidence that Value Line's projections of stock prices represent an investor consensus of the overall market, I place little weight on this first method.

Q. DO YOU HAVE ANOTHER TOTAL RETURN METHOD?

A. Yes. Value Line publishes projections for its Industrial Composite twice each year, and that information can be used to perform a DCF calculation. As of March 2004, Value Line was projecting five-year earnings growth of 5.5 percent and long-term growth from retained earnings of 11.5 percent. Averaging the two measures provides a composite growth rate of 8.5 percent. When combined with Value Line's dividend yield of 1.6 percent for the Industrial Composite, the total return is 10.1 percent.

Q. WHAT ARE THE HISTORICAL RISK PREMIUM VALUES?

A. Mr. Moul reports the historical arithmetic mean risk premium of stocks over bonds (1926-2003) as being 6.6 percent (Schedule 14, page 6 of 6). Combining that updated value with current long-term Treasury yields of about 5.25 percent provides a current market return of 11.85 percent. That same schedule also identifies a geometric mean historical risk premium of 5.0 percent, which translates into a current market return of 10.25 percent (i.e., 5.0% + 5.25%).

There are reasons, however, for believing that even the 6.6 percent historical premium is too high. Recent research by Ibbotson and Chen, estimate a long-term historic risk premium of 5.9 percent (using the arithmetic mean). The authors estimated this figure using a supply-side model removing the effects of a rising P/E ratio over the historical period. This analysis acknowledges that the rising P/Es served to inflate historical returns since such an increase would not be expected to continue indefinitely into the future and is inconsistent with financial theory. Combining the Ibbotson/Chen 5.9 percent risk premium with a current long-term Treasury yield of 5.25 percent produces an overall stock market return of 11.15 percent.[4]

Q. PLEASE SUMMARIZE THE MARKET RETURN EVIDENCE.

A. These four measures of overall stock market return range from 10.1 to 12.4 percent, validating the range used in my CAPM study on page 1 of Schedule MIK-5 of 11 to 12 percent. These measures imply a current stock market risk premium of about 6 percent, which is slightly higher than the 5.67 percent equity risk premium selected by Mr. Moul.

Although Mr. Moul and I are largely in agreement concerning the equity risk premium (for CAPM purposes), our resulting cost of equity estimates differ (for the electric group) by about a percentage point (i.e., 9.6 versus 10.7 percent). This is because Mr. Moul includes two improper adjustments -- the leverage adjustment mentioned earlier and a "size" adjustment. In addition, Mr. Moul employs a forecasted Treasury bond rate rather than using actual market data. I discuss these issues in the next section of my testimony.

[4] *Roger G. Ibbotson and Peng Chen, "Stock Market Returns in the Long Run: Participating in the Real Economy,"* Financial Analyst Journal (forthcoming).

## V. CRITIQUE OF MR. MOUL'S COST OF EQUITY ANALYSIS

### A. Summary of Mr. Moul's Findings

Q. HOW DID MR. MOUL DEVELOP HIS RETURN ON EQUITY RECOMMENDATION?

A. Mr. Moul employs and presents four methods, with two (DCF and CAPM) being cost of equity studies specific to PPLEU, one method (risk premium) being applicable to the broad group of S&P utilities, and the final method (comparable earnings) which does not even attempt to measure the cost of equity at all. The first two methods employ electric delivery and gas distribution proxy groups, and thereby provide a range of results. Mr. Moul's results, inclusive of his various "adders," are as follows:

(1) DCF: 10.69% (electric), 11.22% (gas)

(2) CAPM: 10.71% (electric), 11.22% (gas)

(3) Risk premium: 11.75% (S&P utilities)

(4) Comparable earnings: 14.25% (various non-utilities)

Mr. Moul provides the averages (mean and median) of these results (page 5), and states that he uses results to somehow develop a recommended range of 11.0 to 11.75 percent. He does not indicate how this range was determined, nor does he reveal the weights assigned to these various studies in developing this range. (See response to OCA I-6).

Mr. Moul's final recommendation of 11.5 percent slightly exceeds the midpoint (i.e., 11.38 percent), which is due "in recognition of the exemplary performance of the Company's management." (page 5) In other words, Mr. Moul factors his views regarding management performance into the final ROE recommended figure within this range, but he does not propose a specific numerical adjustment.

Q. GIVEN HIS STUDY RESULTS, IS 11.0 TO 11.75 PERCENT A REASONABLE ROE RANGE?

A. No, it is not. Mr. Moul obtains 10.69 and 10.71 percent for his electric distribution DCF and CAPM studies, respectively. The gas distribution studies are irrelevant since they reflect the cost of equity and business risks of a different industry, and not surprisingly, this provides a higher cost of capital result. The historic risk premium also has little to do with PPLEU's distribution operations, and the comparable earnings study does not even attempt measure the cost of equity.

Thus, Mr. Moul's PPLEU-specific cost of equity evidence -- even if correct -- could not support a fair return exceeding 10.7 percent, reflecting the electric delivery service DCF and CAPM results.

Q. MR. MOUL'S 10.7 PERCENT ELECTRIC DISTRIBUTION RESULTS EXCEED YOUR 9.5 PERCENT RECOMMENDATION. WHY IS THAT?

A. There are a number of differences between our respective analyses, but the key reasons why I believe that his 10.7 percent overstates the cost of equity are: (a) his use of an unrealistically high earnings growth rate in his DCF analysis; (b) his inclusion of a market/book or "leverage" adjustment; and (c) a size adjustment in his CAPM study.

**B. <u>The DCF Study</u>**

Q. HOW DID MR. MOUL OBTAIN HIS 10.69 PERCENT DCF ESTIMATE?

A. Using the standard DCF model, applied to a proxy group of delivery service companies, he obtains 10.25 percent, i.e., an adjusted yield of 4.75 percent plus a growth factor of 5.5 percent. He then adds 0.44 percentage points for "leveraged" to obtain 10.69 percent.

Q. HOW DOES HE OBTAIN A GROWTH FACTOR OF 5.5 PERCENT?

A. This is very difficult to determine from his testimony, appendices or exhibits. His response to OCA I-7 seems to indicate that he assigns the most weight to published

projections of earnings (as do I), but he is no more specific than that. His Schedule 11 shows the following proxy group projections of five-year earnings growth rates.

| | |
|---|---|
| First Call/IBES | 3.78% |
| Zacks | 4.00 |
| Reuters Multex | 3.81 |
| Value Line | 5.72 |
| **Average** | **4.33%** |

Please note that Value Line growth rates tend to be quite volatile and currently are much lower than the 5.72 percent that Mr. Moul reports. Value Line projections of other variable (dividends, cash flow, internal growth, book value) average only 3.3 percent, and historical growth rates are even lower.

Clearly, the available data could support a proxy group (midpoint) growth rate of about 4 percent, but not higher than that, and certainly nowhere close to 5.5 percent.

Q. MR. MOUL ALSO CITES LONG-TERM EARNINGS GROWTH OF ABOUT 6 PERCENT FROM THE BLUE CHIP CONSENSUS FORECAST. WOULD THIS HELP TO SUPPORT HIS CONCLUSION OF 5.5 PERCENT?

A. No, if anything, it would contradict it and demonstrate that the 5.5 percent figure is far too high. The 6 percent long-term growth forecast he cites is for total U.S. corporate earnings -- not the distribution proxy companies. These companies are stable, slow growth utilities that both in the near-term and long run are expected to exhibit earnings growth much slower than corporations generally. These are dividend paying stocks (i.e., 5.0 percent average yield versus about 1.6 percent for corporations generally) that payout most of their earnings as dividends rather than reinvesting most (or all) for long-term growth. In addition, these companies are mostly limited to regulated returns, which further restricts their growth potential.

If the long-term outlook for corporate earnings growth is 6 percent, then it follows that the growth outlook for the distribution electrics must be significantly less than that – probably not more than about 4 percent.

Q. DO YOU FIND ANY SUPPORT IN HIS TESTIMONY OR EXHIBITS FOR HIS 5.5 PERCENT GROWTH FACTOR?

A. No, I do not.

Q. *DO YOU SEE THE SAME PROBLEM WITH HIS GAS PROXY GROUP?*

A. Yes, according to page 2 of his Schedule 11, the analyst growth rate projections of earnings for the gas proxy group are:

| | |
|---|---|
| First Call/IBES | 5.50% |
| Zacks | 5.38 |
| Reuters Multex | 5.38 |
| Value Line | 6.71 |
| **Average** | **5.74%** |

Once again, I must note that Value Line earnings projections can sometimes can be quite volatile, and the other three measures are 5.38 to 5.5 percent.

Mr. Moul selects 6.25 percent, a growth rate expectation that seems unreasonably high. The analyst projections would support a growth expectation of about 5.7 percent, and hence a DCF result of 9.9 percent. This result reflects gas industry risks, and is not applicable to PPLEU's electric distribution operations.

Q. MR. MOUL INCLUDES 0.44 PERCENT FOR "LEVERAGE" AS AN ADJUSTMENT TO THE DCF RESULT. DOES THE DCF ANALYSIS REQUIRE AN ADJUSTMENT?

A. No. The DCF model does not require a "leverage" adjustment to produce an accurate cost of equity estimate. The inclusion of this adjustment causes an overstatement of the cost of equity, and, therefore, this adjustment must be removed.

C. **Mr. Moul's Leverage Adjustment**

Q. WHAT IS MR. MOUL'S RATIONALE FOR THIS ADJUSTMENT?

A. Mr. Moul claims that a leverage adjustment is needed because the capital structure used for rate of return purposes is based upon book value:

> the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity account measured at book value, which is the measure used in setting utility rates. (page 34)

He further alleges that as a result of this "conflict," "the DCF can result in a mis-specified cost of equity." (page E-4)

Q. IS THERE ANY MERIT TO THIS ARGUMENT?

A. There is no basis for this adjustment in financial theory, and it is a departure from the accepted cost of capital standard. Moreover, the adjustment is counterintuitive because it implies that the higher a company's stock price, the larger the ROE leverage adjustment that would be needed. But an increase in the Company's stock price is likely to be the result of declining capital costs, and therefore a lower, not a higher, ROE would be appropriate.

Q. DOES THE DCF MODEL MISSTATE THE COST OF CAPITAL WHEN MARKET VALUE EXCEEDS BOOK VALUE, AS MR. MOUL CLAIMS?

A. No. In considering this issue it is necessary to understand how Mr. Moul and I have employed the DCF model. What is at issue in this case is the cost of common equity for PPLEU. However, because we cannot apply the DCF to PPLEU, we instead select groups of proxy companies, i.e., companies judged to be similar in risk to PPLEU. The DCF model application estimates the market return investors expect to received from investing in those companies. If one assumes Mr. Moul's DCF data to be accurate, the cost of equity for the proxy companies would be 10.25 percent:

4.75% (dividend yield) + 5.5% (growth rate) = 10.25%

Once we have the proxy group DCF result, we move to the next question: how does PPLEU's risk (i.e., business and financial) compare with the proxy group average? If there is reason to believe PPLEU is a riskier company, then a risk adjustment could be proposed. However, Mr. Moul has made no such claim, and similarly, I see no basis for a risk adjustment. Thus, the proxy group DCF (with no adjustment) is the best estimate we have of PPLEU's cost of equity.

Q. IS PPLEU MORE LEVERAGED THAN THE PROXY GROUP COMPANIES?

A. No, on average PPLEU is somewhat less leveraged. PPLEU has a 46 percent equity ratio (nearly 47 percent under Mr. Moul's recommendation) compared to 43 percent for the proxy group average. Thus, under accepted finance theory, if a leverage adjustment were to be considered, it would be a downward adjustment, not an upward adjustment.

Q. MR. MOUL POINTS OUT THAT FOR THE PROXY COMPANIES THE MARKET EQUITY RATIO EXCEEDS THE BOOK EQUITY RATIO. DOES THE DCF STUDY NEED TO BE ADJUSTED TO TAKE THAT INTO ACCOUNT?

A. No. It is already fully accounted for in the DCF study. The amount of leverage (market or book, or both) that these proxy companies have is of interest to investors, and is fully captured in the DCF study, which measures the investors' return requirement. Using Mr. Moul's 10.25 percent result, the DCF estimate automatically reflects all investor-perceived risk, including debt leverage-related risk. As I just stated above, PPLEU has less, not more, leverage than the proxy companies.

This leads to a disturbing conclusion. By including his adjustment, Mr. Moul has double counted the effect of leverage. The actual leverage of the proxy companies

already is fully reflected in his 10.25 percent unadjusted DCF. His 0.44 percent adjustment adds in the (alleged) effect of leverage a second time.

Q. DOES MR. MOUL CITE ANY AUTHORITY THAT VALIDATES HIS ADJUSTMENT?

A. No. While he cites the work of Miller-Modigliani (MM) published several decades ago, he misunderstands and misuses their work in his application. In fact, the MM analysis would lead to precisely the opposite conclusion of that derived by Mr. Moul.

The MM theoretical work establishes that a firm's valuation and cost of capital (all else equal) is affected by its market capital structure, i.e., the more the leverage in the capital structure, the higher the cost of equity. Hence, if a DCF study produced a 10.25 percent expected return (cost of equity), that cost of equity would reflect whatever market capital structure those firms have. If the market capital structure changes, then the cost of capital changes (again, all else equal). In other words, the MM theory confirms that leverage (including any market/book difference) should be fully reflected in stock prices and therefore the DCF calculations.

Q. DOES THE MM WORK SUPPORT A MARKET TO BOOK ADJUSTMENT?

A. No, the cited work deals how market leverage affects asset valuation. It does not deal in any way with market-to-book type adjustments or utility ratemaking.

Q. TO YOUR KNOWLEDGE, HAS MR. MOUL'S DCF ADJUSTMENT BEEN ACCEPTED IN OTHER JURISDICTIONS?

A. To my knowledge, it has not been accepted other jurisdictions.

Q. IS THE ADJUSTMENT NEEDED TO PROVIDE PPLEU WITH AN ADEQUATE RETURN?

A. No, it is not. As I have shown, the standard application of the DCF model identifies the cost of equity and fully accounts for the actual amount of debt leverage, regardless if one

uses market or book leverage. In fact, it takes into account all risk factors. The cost of equity fully compensates investors at a market rate. Mr. Moul's adjustment is an improper departure from cost-based ratemaking.

Q. DOES THE MARKET PRICE VERSUS BOOK VALUE DIVERGENCE IN ANY WAY AFFECT THE AMOUNT OF A COMPANY'S FIXED INCOME OBLIGATIONS?

A. No, the simple fact that a company's stock price exceeds its book value by itself does not affect its total fixed income obligations (e.g., the amount of debt or annual interest expense). However, here is the crucial point: whatever the degree of a company's financial leverage or risk, it is fully accounted for in the standard DCF analysis. Certainly, it makes no sense to argue that the mere fact that a company's stock price exceeds its book value causes investors to perceive higher financial risk and therefore require a higher return.

Q. WHY WOULD A COMPANY'S STOCK PRICE EXCEED BOOK VALUE?

A. One reason could be that investors are expecting earnings (i.e., earned returns on equity) in the future that exceed the Company's market cost of equity. Mr. Moul's adjustment, therefore, is intended to help ensure that the stock price remains above book value. The determination by this Commission of a fair rate of return need not target any specific stock price, and it certainly is not appropriate to include a "premium" over the cost of equity merely to ensure that the stock price exceeds book value. In the case of PPLEU, this is particularly inappropriate because the stock price is that of the largely unregulated PPL Corporation.

Q. HAS MR. MOUL PRESENTED ANY EVIDENCE THE RATE OF RETURN AWARD BASED ON THE COST OF EQUITY -- ABSENT THE LEVERAGE

ADJUSTMENT -- WILL FAIL TO PROTECT PPLEU'S FINANCIAL INTEGRITY AND ACCESS TO CAPITAL?

A. None whatsoever. In fact, I have shown that my 9.5 percent ROE, in combination of the book capital structure, produces very acceptable financial ratios (i.e., interest coverage, debt ratio, cash flow measures).

Q. SETTING ASIDE THE ISSUE OF WHETHER THE LEVERAGE ADJUSTMENT IS NEEDED, HAS IT BEEN CORRECTLY CALCULATED?

A. No, it is not properly calculated because he has drastically overstated the difference between market and book capital structure. Mr. Moul calculates a market equity ratio for his proxy group of about 50 percent and compares it to the group book equity ratio of 43 percent. This is an incorrect comparison. We are not setting the rate of return in this case for the proxy companies, but rather for PPLEU. The Company's claimed book equity ratio for rate of return purposes is 46.9 percent, or a difference from the proxy group market equity ratio of only about 3 percentage points, not 7 percentage points. Moreover, in calculating the proxy group market capital structure, Mr. Moul erroneously omits short-term debt. There is nothing in the Miller-Modigliani leverage formulation that permits this exclusion. This causes an overstatement in the proxy group market equity ratio, and correcting for that would reduce the market versus book difference even further -- perhaps to 2 percentage points. Thus, Mr. Moul's calculation of the leverage adjustment (44 basis points) is at least three to four times too large. His calculation using the PPLEU book capital structure would provide a leverage adjustment on the order of about 0.1 percent.

Again, I believe the adjustment is not needed at all absent evidence that PPLEU's risk exceeds that of the proxy group companies. Market versus book differences should not be the basis for a rate of return adder.

Q. DO YOU SEE ANY OTHER REASON WHY AN ROE ADDER IS IMPROPER?

A. Yes. In its restructuring case, the Company requested and received a large revenue award for its stranded costs. The basis for such an award is the determination that the market value of the utility's generation assets was less than the book value. In this case, the Company is turning that concept on its head by seeking an ROE adjustment to recognize that the market value of its equity exceeds the book value.

Q. WHAT DO YOU CONCLUDE REGARDING MR. MOUL'S DCF?

A. Using a more reasonable growth factor and eliminating the leverage factor (or even properly correcting the factor so that it reflects PPLEU), his DCF would produce a return in the 9 to 10 percent range.

**D. The CAPM Study**

Q. WHAT ARE YOUR CONCERNS REGARDING THE CAPM STUDY?

A. I have three main concerns. First, his risk free rate (Treasury bond yield) is based on forecasts rather than actual market data. Second, his analysis includes a leverage adjustment similar to the one I just discussed in connection with his DCF study. This adjustment is both conceptually and empirically wrong in the CAPM for precisely the same reasons that I discuss above. Third, he includes a "size" adjustment of (0.82 percent), apparently based on the notion that small capitalization stocks are riskier than large capitalization stocks. This adjustment is erroneous.

Q. DO YOUR CRITICISMS OF THE DCF LEVERAGE ADJUSTMENT APPLY TO HIS CAPM STUDY?

A. Yes, the same criticisms apply here. In addition to the fact that the use of book equity for capital structure needs no correction, he fails to base his calculation on PPLEU's ratemaking equity ratio. For example, PPLEU could have proposed a 75 percent equity

ratio for ratemaking purposes, and it would not have affected his leverage adjustment calculation at all since he ignores PPLEU's book equity.

Q. WHAT IS WRONG WITH THE USE OF A FORECAST OF THE RISK-FREE RATE?

A. While I understand Mr. Moul's desire to take into account the rising interest rate trend, I believe it is preferable to use actual market data. Forecasts are estimates based on assumptions concerning things that might or might not happen, in the future, and in that sense are speculative. This would be equivalent to basing the DCF analysis on projected stock prices of the proxy companies rather than using recent actuals.

Q. WHY DOES MR. MOUL INCLUDE A SIZE ADJUSTMENT (0.82 PERCENT)?

A. He cites evidence that investors generally see small stocks as being riskier than large stocks. While there is some support for this view (although not necessarily for utility companies), he does not explain the source or calculation of his 0.82 percent adder.

Q. IS IT PROPER TO INCLUDE THE SIZE ADJUSTMENT IN A CAPM STUDY?

A. No, the adjustment is not warranted. Even if one were to accept Mr. Moul's view that size (by itself) is a risk factor, then this would tend to be reflected in the individual company betas, and therefore automatically captured in the CAPM results, with no external adjustment being needed. His adjustment double counts "size risk," assuming size risk is present at all.

Q. ARE THERE SIZE DISCREPANCIES IN HIS CAPM?

A. Possibly, although his testimony does not document this very well. The risk premium data are derived from Ibbotson "large stocks" (a mix of large cap and medium cap stocks) and Value Line (a mix of large, medium and small cap stocks). His electric proxy group

includes at least three utilities classified as "small cap" (C.H. Energy and the two Vermont companies), and I must assume that it is these small cap companies that are the reason for his proposed size adjustment.

Q. THE PURPOSE OF THE CAPM IS TO IDENTIFY PPLEU'S COST OF EQUITY. IS PPLEU SMALL CAP?

A. No. Value Line classifies PPL Corporation as "large cap," and thus if a size adjustment is employed (and in my opinion it should not be), the adjustment should be negative, not a positive 0.82 percent. PPLEU is a multi-billion dollar company, and if it were to be spun off on its own, it probably would be "mid cap." But the point is that it is part of (and contributes to the size of) a large cap corporation, and therefore there can be no basis for increasing the CAPM results, when estimating PPLEU's cost of equity.

**E. <u>Risk Premium Analysis</u>**

Q. HOW DID MR. MOUL CONDUCT HIS RISK PREMIUM ANALYSIS?

A. This method compares the after-the-fact returns on utility stocks with returns on utility bonds over an extended historical period. After considering various time periods and measurement techniques, he concludes that the risk premium is about 4.50 percent. He combined this value with a 7.25 percent forecast yield on single A utility bonds to obtain a final 11.75 percent risk premium cost of equity.

I have already discussed my concerns with the reliance on forecast bond yields in the context of the CAPM and will not repeat that discussion. In addition, Mr. Moul has selected a cost of debt of 6.43 percent (see page E-15) for purposes of his DCF "leverage" adjustment, whereas for his risk premium study he uses a bond yield of 7.25 percent. At a minimum, this is a troubling inconsistency.

Q. ARE THERE OTHER PROBLEMS WITH THIS ANALYSIS?

A. Yes, there is an assortment of problems, including the fact the S&P Public Utility Index over the historical period probably has little to do with PPLEU's electric delivery service. The S&P index that he uses includes a diverse group of gas and electric generation utilities, and includes only one large electric delivery service company. (See his Schedule 5, page 2.) The historical time period used in his study was almost entirely pre-restructuring, and thus almost all electrics in the group are fully integrated companies.

There is no evidence that Mr. Moul's after-the-fact historical return results are employed today by investors, or that investors are even aware of the risk premium/historic return data that Mr. Moul compiles on his Schedule 13. Moreover, his historical return data do not take into account changing conditions that influence the cost of equity (and the equity risk premium), such as the recent changes in federal tax law that I discussed earlier. For this reason alone, his historic risk premium is overstated.

Q. DO YOU SEE ANY OTHER PROBLEMS THAT LEAD YOU TO QUESTION THE VALIDITY OF THIS ANALYSIS?

A. Yes. One can perform a reasonableness check by comparing these results to the Ibbotson historical data series, shown in Mr. Moul's Direct Testimony, on page 6 of Schedule 14. Mr. Moul reports a return on public utility bonds of 5.79 percent for 1928-2003, but for a nearly identical historical period (i.e., 1926-2003) the return on long-term Treasury bonds was 5.8 percent. In other words, there is almost no return difference in his historical averages between long-term Treasury and utility bonds. Even if that result was correct during the historical period (which seems unlikely), it clearly is not the case today. As Mr. Moul's Schedule 12 shows, the single A utility bond versus long-term Treasury bond yield spread in recent years, has been on the order of 100 to 200 basis points.

The historical returns data that Mr. Moul employs for his risk premium study are not reflective of current investor requirements for distribution electric companies, such as PPLEU.

**F. Comparable Earnings**

Q. HOW DID MR. MOUL ESTIMATE THE COST OF EQUITY USING THE COMPARABLE EARNINGS METHOD?

A. I must point out that this is not a cost of equity method at all, and it, therefore, was not used to estimate PPLEU's cost of equity, as he himself acknowledges (response to OCA Set I-10). Rather, Mr. Moul has compiled historical and (Value Line) projected returns on book equity for a group of non-utility companies. This compilation of accounting returns data provides a "comparable earnings" return on equity of 14.25 percent.

Q. WHY DOES MR. MOUL USE THIS METHOD?

A. His testimony implies that the comparable earnings standard for fair rate of return is supported by the U.S. Supreme Court's Hope decision:

> The Hope decision requires that a fair return for a utility must be equal to that earned by firms of comparable risk. (Moul, D-3)

Q. DO YOU AGREE WITH HIS ASSESSMENT?

A. I am not venturing a legal opinion on the Hope decision and what it requires of regulators. However, I believe Mr. Moul's logic in applying this interpretation of Hope is in error. Assuming the 14.25 percent value is representative of unregulated returns on book equity, this is of only limited interest to the investor. Rather, the investor's ultimate interest is in a company's market return, not its book return, and the (expected) market return is properly determined by a DCF (or CAPM) analysis. Since the investor today purchasing stock typically must pay a price exceeding book value, the 14.25 percent book

return is not the rate of return the investor either will or can expect to receive if he invests his funds today. He or she expects to earn much less than that. Consequently, the comparable earnings analysis is of no value for the task at hand, i.e., ascertaining investor return requirements at this time.

Q. DO YOU HAVE ANY OTHER OBJECTIONS TO THIS ANALYSIS?

A. Yes. My overriding disagreement with reliance on a comparable earnings study is that it represents a rejection of cost-based ratemaking, and in doing so it provides the utility with an excessive return. I would note, however, that Mr. Moul does not recommend his comparable earnings result, 14.25 percent, but a return much lower than that, i.e., 11.5 percent.

Q. DO THE FIRMS IN MR. MOUL'S GROUP OPERATE IN COMPETITIVE MARKETS?

A. That is an unknown. Mr. Moul only states that these are "unregulated firms," and he has conducted no review to determine whether any of these firms possess market power or whether any of the earnings reflect monopoly profits. (See response to OCA Set I-12.)

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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# APPENDIX A

## STATEMENT OF QUALIFICATIONS

# MATTHEW I. KAHAL

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 200 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

**Education:**

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

**Previous Employment:**

1981-2001 - Exeter Associates, Inc. (founding Principal).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

**Professional Work Experience:**

Mr. Kahal has more than twenty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at

Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

**Publications and Consulting Reports:**

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).

**Conference and Workshop Presentations:**

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

Expert Testimony
of Matthew I. Kahal

| | Docket Number | Utility | Jurisdiction | Client | Subject |
|---|---|---|---|---|---|
| 1. | 27374 & 27375<br>October 1978 | Long Island Lighting Company | New York Counties | Nassau & Suffolk | Economic impacts of proposed rate increase |
| 2. | 6807<br>January 1978 | Generic | Maryland | MD Power Plant Siting Program | Load forecasting |
| 3. | 78-676-EL-AIR<br>February 1978 | Ohio Power Company | Ohio | Ohio Consumers' Counsel | Test year sales and revenues |
| 4. | 17667<br>May 1979 | Alabama Power Company | Alabama | Attorney General | Test year sales, revenues, costs and load forecasts |
| 5. | None<br>April 1980 | Tennessee Valley Authority | TVA Board | League of Women Voters | Time-of-use pricing |
| 6. | R-80021082 | West Penn Power Company | Pennsylvania | Office of Consumer Advocate | Load forecasting, marginal cost pricing |
| 7. | 7259 (Phase I)<br>October 1980 | Potomac Edison Company | Maryland | MD Power Plant Siting Program | Load forecasting |
| 8. | 7222<br>December 1980 | Delmarva Power & Light Company | Maryland | MD Power Plant Siting Program | Need for plant, load forecasting |
| 9. | 7441<br>June 1981 | Potomac Electric Power Company | Maryland | Commission Staff | PURPA standards |
| 10. | 7159<br>May 1980 | Baltimore Gas & Electric | Maryland | Commission Staff | Time-of-use pricing |
| 11. | 81-044-E-42T | Monongahela Power | West Virginia | Commission Staff | Time-of-use rates |
| 12. | 7259 (Phase II)<br>November 1981 | Potomac Edison Company | Maryland | MD Power Plant Siting Program | Load forecasting, load management |
| 13. | 1606<br>September 1981 | Blackstone Valley Electric and Narragansett | Rhode Island | Division of Public Utilities | PURPA standards |
| 14. | RID 1819<br>April 1982 | Pennsylvania Bell | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 15. | 82-0152<br>July 1982 | Illinois Power Company | Illinois | U.S. Department of Defense | Rate of return, CWIP |
| 16. | 7559<br>September 1982 | Potomac Edison Company | Maryland | Commission Staff | Cogeneration |
| 17. | 820150-EU<br>September 1982 | Gulf Power Company | Florida | Federal Executive Agencies | Rate of return, CWIP |

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|---|---|---|---|---|---|
| 18. | 82-057-15<br>January 1983 | Mountain Fuel Supply Company | Utah | Federal Executive Agencies | Rate of return, capital structure |
| 19. | 5200<br>August 1983 | Texas Electric Service Company | Texas | Federal Executive Agencies | Cost of equity |
| 20. | 28069<br>August 1983 | Oklahoma Natural Gas | Oklahoma | Federal Executive Agencies | Rate of return, deferred taxes, capital structure, attrition |
| 21. | 83-0537<br>February 1984 | Commonwealth Edison Company | Illinois | U.S. Department of Energy | Rate of return, capital structure, financial capability |
| 22. | 84-035-01<br>June 1984 | Utah Power & Light Company | Utah | Federal Executive Agencies | Rate of return |
| 23. | U-1009-137<br>July 1984 | Utah Power & Light Company | Idaho | U.S. Department of Energy | Rate of return, financial condition |
| 24. | R-842590<br>August 1984 | Philadelphia Electric Company | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 25. | 840086-EI<br>August 1984 | Gulf Power Company | Florida | Federal Executive Agencies | Rate of return, CWIP |
| 26. | 84-122-E<br>August 1984 | Carolina Power & Light Company | South Carolina | South Carolina Consumer Advocate | Rate of return, CWIP, load forecasting |
| 27. | CGC-83-G & CGC-84-G<br>October 1984 | Columbia Gas of Ohio | Ohio | Ohio Division of Energy | Load forecasting |
| 28. | R-842621<br>October 1984 | Western Pennsylvania Water Company | Pennsylvania | Office of Consumer Advocate | Test year sales |
| 29. | R-842710<br>January 1985 | ALLTEL Pennsylvania Inc. | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 30. | ER-504<br>February 1985 | Allegheny Generating Company | FERC | Office of Consumer Advocate | Rate of return |
| 31. | R-842632<br>March 1985 | West Penn Power Company | Pennsylvania | Office of Consumer Advocate | Rate of return, conservation, time-of-use rates |
| 32. | 83-0537 & 84-0555<br>April 1985 | Commonwealth Edison Company | Illinois | U.S. Department of Energy | Rate of return, incentive rates, rate base |

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|---|---|---|---|---|---|
| 33. | Rulemaking Docket No. 11, May 1985 | Generic | Delaware | Delaware Commission Staff | Interest rates on refunds |
| 34. | 29450 July 1985 | Oklahoma Gas & Electric Company | Oklahoma | Oklahoma Attorney General | Rate of return, CWIP in rate base |
| 35. | 1811 August 1985 | Bristol County Water Company | Rhode Island | Division of Public Utilities | Rate of return, capital structure |
| 36. | R-850044 & R-850045 August 1985 | Quaker State & Continental Telephone Companies | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 37. | R-850174 November 1985 | Philadelphia Suburban Water Company | Pennsylvania | Office of Consumer Advocate | Rate of return, financial conditions |
| 38. | U-1006-265 March 1986 | Idaho Power Company | Idaho | U.S. Department of Energy | Power supply costs and models |
| 39. | EL-86-37 & EL-86-38 September 1986 | Allegheny Generating Company | FERC | PA Office of Consumer Advocate | Rate of return |
| 40. | R-850287 June 1986 | National Fuel Gas Distribution Corp. | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 41. | 1849 August 1986 | Blackstone Valley Electric | Rhode Island | Division of Public Utilities | Rate of return, financial condition |
| 42. | 86-297-GA-AIR November 1986 | East Ohio Gas Company | Ohio | Ohio Consumers' Counsel | Rate of return |
| 43. | U-16945 December 1986 | Louisiana Power & Light Company | Louisiana | Public Service Commission | Rate of return, rate phase-in plan |
| 44. | Case No. 7972 February 1987 | Potomac Electric Power Company | Maryland | Commission Staff | Generation capacity planning, purchased power contract |
| 45. | EL-86-58 & EL-86-59 March 1987 | System Energy Resources and Middle South Services | FERC | Louisiana PSC | Rate of return |
| 46. | ER-87-72-001 April 1987 | Orange & Rockland | FERC | PA Office of Consumer Advocate | Rate of return |
| 47. | U-16945 April 1987 | Louisiana Power & Light Company | Louisiana | Commission Staff | Revenue requirement update phase-in plan |
| 48. | P-870196 May 1987 | Pennsylvania Electric Company | Pennsylvania | Office of Consumer Advocate | Cogeneration contract |

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|---|---|---|---|---|---|
| 49. | 86-2025-EL-AIR<br>June 1987 | Cleveland Electric Illuminating Company | Ohio | Ohio Consumers' Counsel | Rate of return |
| 50. | 86-2026-EL-AIR<br>June 1987 | Toledo Edison Company | Ohio | Ohio Consumers' Counsel | Rate of return |
| 51. | 87-4<br>June 1987 | Delmarva Power & Light Company | Delaware | Commission Staff | Cogeneration/small power |
| 52. | 1872<br>July 1987 | Newport Electric Company | Rhode Island | Commission Staff | Rate of return |
| 53. | WO 8606654<br>July 1987 | Atlantic City Sewerage Company | New Jersey | Resorts International | Financial condition |
| 54. | 7510<br>August 1987 | West Texas Utilities Company | Texas | Federal Executive Agencies | Rate of return, phase-in |
| 55. | 8063 Phase I<br>October 1987 | Potomac Electric Power Company | Maryland | Power Plant Research Program | Economics of power plant site selection |
| 56. | 00439<br>November 1987 | Oklahoma Gas & Electric Company | Oklahoma | Smith Cogeneration | Cogeneration economics |
| 57. | RP-87-103<br>February 1988 | Panhandle Eastern Pipe Line Company | FERC | Indiana Utility Consumer Counselor | Rate of return |
| 58. | EC-88-2-000<br>February 1988 | Utah Power & Light Co.<br>PacifiCorp | FERC | Nucor Steel | Merger economics |
| 59. | 87-0427<br>February 1988 | Commonwealth Edison Company | Illinois | Federal Executive Agencies | Financial projections |
| 60. | 870840<br>February 1988 | Philadelphia Suburban Water Company | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 61. | 870832<br>March 1988 | Columbia Gas of Pennsylvania | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 62. | 8063 Phase II<br>July 1988 | Potomac Electric Power Company | Maryland | Power Plant Research Program | Power supply study |
| 63. | 8102<br>July 1988 | Southern Maryland Electric Cooperative | Maryland | Power Plant Research Program | Power supply study |
| 64. | 10105<br>August 1988 | South Central Bell Telephone Co. | Kentucky | Attorney General | Rate of return, incentive regulation |

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|---|---|---|---|---|---|
| 65. | 00345<br>August 1988 | Oklahoma Gas & Electric Company | Oklahoma | Smith Cogeneration | Need for power |
| 66. | U-17906<br>September 1988 | Louisiana Power & Light Company | Louisiana | Commission Staff | Rate of return, nuclear power costs<br>Industrial contracts |
| 67. | 88-170-EL-AIR<br>October 1988 | Cleveland Electric Illuminating Co. | Ohio | Northeast-Ohio Areawide Coordinating Agency | Economic impact study |
| 68. | 1914<br>December 1988 | Providence Gas Company | Rhode Island | Commission Staff | Rate of return |
| 69. | U-12636 & U-17649<br>February 1989 | Louisiana Power & Light Company | Louisiana | Commission Staff | Disposition of litigation proceeds |
| 70. | 00345<br>February 1989 | Oklahoma Gas & Electric Company | Oklahoma | Smith Cogeneration | Load forecasting |
| 71. | RP88-209<br>March 1989 | Natural Gas Pipeline of America | FERC | Indiana Utility Consumer Counselor | Rate of return |
| 72. | 8425<br>March 1989 | Houston Lighting & Power Company | Texas | U.S. Department of Energy | Rate of return |
| 73. | EL89-30-000<br>April 1989 | Central Illinois Public Service Company | FERC | Soyland Power Coop, Inc. | Rate of return |
| 74. | R-891208<br>May 1989 | Pennsylvania American Water Company | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 75. | 89-0033<br>May 1989 | Illinois Bell Telephone Company | Illinois | Citizens Utility Board | Rate of return |
| 76. | 881167-EI<br>May 1989 | Gulf Power Company | Florida | Federal Executive Agencies | Rate of return |
| 77. | R-891218<br>July 1989 | National Fuel Gas Distribution Company | Pennsylvania | Office of Consumer Advocate | Sales forecasting |
| 78. | 8063, Phase III<br>Sept. 1989 | Potomac Electric Power Company | Maryland | Depart. Natural Resources | Emissions Controls |
| 79. | 37414-S2<br>October 1989 | Public Service Company of Indiana | Indiana | Utility Consumer Counselor | Rate of return, DSM, off-system sales, incentive regulation |

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|---|---|---|---|---|---|
| 80. | October 1989 | Generic | U.S. House of Reps. Comm. on Ways & Means | NA | Excess deferred income tax |
| 81. | 38728 November 1989 | Indiana Michigan Power Company | Indiana | Utility Consumer Counselor | Rate of return |
| 82. | RP89-49-000 December 1989 | National Fuel Gas Supply Corporation | FERC | PA Office of Consumer Advocate | Rate of return |
| 83. | R-891364 December 1989 | Philadelphia Electric Company | Pennsylvania | PA Office of Consumer Advocate | Financial impacts (surrebuttal only) |
| 84. | RP89-160-000 January 1990 | Trunkline Gas Company | FERC | Indiana Utility Consumer Counselor | Rate of return |
| 85. | EL90-16-000 November 1990 | System Energy Resources, Inc. | FERC | Louisiana Public Service Commission | Rate of return |
| 86. | 89-624 March 1990 | Bell Atlantic | FCC | PA Office of Consumer Advocate | Rate of return |
| 87. | 8245 March 1990 | Potomac Edison Company | Maryland | Depart. Natural Resources | Avoided Cost |
| 88. | 000586 March 1990 | Public Service Company of Oklahoma | Oklahoma | Smith Cogeneration Mgmt. | Need for Power |
| 89. | 38868 March 1990 | Indianapolis Water Company | Indiana | Utility Consumer Counselor | Rate of return |
| 90. | 1946 March 1990 | Blackstone Valley Electric Company | Rhode Island | Division of Public Utilities | Rate of return |
| 91. | 000776 April 1990 | Oklahoma Gas & Electric Company | Oklahoma | Smith Cogeneration Mgmt. | Need for Power |
| 92. | 890366 May 1990, December 1990 | Metropolitan Edison Company | Pennsylvania | Office of Consumer Advocate | Competitive Bidding Program Avoided Costs |
| 93. | EC-90-10-000 May 1990 | Northeast Utilities | FERC | Maine PUC, et. al. | Merger, Market Power, Transmission Access |
| 94. | ER-891109125 July 1990 | Jersey Central Power & Light | New Jersey | Rate Counsel | Rate of return |
| 95. | R-901670 July 1990 | National Fuel Gas Distribution Corp. | Pennsylvania | Office of Consumer Advocate | Rate of return Test year sales |

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|---|---|---|---|---|---|
| 96. | 8201<br>October 1990 | Delmarva Power & Light Company | Maryland | Depart. Natural Resources | Competitive Bidding, Resource Planning |
| 97. | EL90-45-000<br>April 1991 | Entergy Services, Inc. | FERC | Louisiana PSC | Rate of return |
| 98. | GR90080786J<br>January 1991 | New Jersey Natural Gas | New Jersey | Rate Counsel | Rate of return |
| 99. | 90-256<br>January 1991 | South Central Bell Telephone Co. | Kentucky | Attorney General | Rate of return |
| 100. | U-17949A<br>February 1991 | South Central Bell Telephone Co. | Louisiana | Louisiana PSC | Rate of return |
| 101. | ER90091090J<br>April 1991 | Atlantic City Electric Company | New Jersey | Rate Counsel | Rate of return |
| 102. | 8241, Phase I<br>April 1991 | Baltimore Gas & Electric Co. | Maryland | Dept. of Natural Resources | Environmental controls |
| 103. | 8241, Phase II<br>May 1991 | Baltimore Gas & Electric Company | Maryland | Dept. of Natural Resources | Need for Power, Resource Planning |
| 104. | 39128<br>May 1991 | Indianapolis Water Company | Indiana | Utility Consumer Counselor | Rate of return, rate base, financial planning |
| 105. | P-900485<br>May 1991 | Duquesne Light Company | Pennsylvania | Office of Consumer Advocate | Purchased power contract and related ratemaking |
| 106. | G900240<br>P910502<br>May 1991 | Metropolitan Edison Co.<br>Pennsylvania Electric Co. | Pennsylvania | Office of Consumer Advocate | Purchased power contract and related ratemaking |
| 107. | GR901213915<br>May 1991 | Elizabethtown Gas Co. | New Jersey | Rate Counsel | Rate of return |
| 108. | 91-5032<br>August 1991 | Nevada Power Co. | Nevada | U.S. Dept. of Energy | Rate of return |
| 109. | EL90-48-000<br>November 1991 | Entergy Services | FERC | Louisiana PSC | Capacity transfer |
| 110. | 000662<br>September 1991 | Southwestern Bell Telephone | Oklahoma | Attorney General | Rate of return |

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|---|---|---|---|---|---|
| 111. | U-19236<br>October 1991 | Arkansas Louisiana Gas Company | Louisiana | Louisiana PSC Staff | Rate of return |
| 112. | U-19237<br>December 1991 | Louisiana Gas Service Company | Louisiana | Louisiana PSC Staff | Rate of return |
| 113. | ER91030356J<br>October 1991 | Rockland Electric Company | New Jersey | Rate Counsel | Rate of return |
| 114. | GR91071243J<br>February 1992 | South Jersey Gas Company | New Jersey | Rate Counsel | Rate of return |
| 115. | GR91081393J<br>March 1992 | New Jersey Natural Gas Company | New Jersey | Rate Counsel | Rate of return |
| 116. | P-870235 et al.<br>March 1992 | Pennsylvania Electric Company | Pennsylvania | Office of Consumer Advocate | Cogeneration contracts |
| 117. | 8413<br>March 1992 | Potomac Electric Power Company | Maryland | Dept. of Natural Resources | IPP purchased power contracts |
| 118. | 39236<br>March 1992 | Indianapolis Power & Light Company | Indiana | Utility Consumer Counselor | Least-cost planning<br>Need for power |
| 119. | R-912164<br>April 1992 | Equitable Gas Company | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 120. | ER-91111698J<br>May 1992 | Public Service Electric & Gas Company | New Jersey | Rate Counsel | Rate of return |
| 121. | U-19631<br>June 1992 | Trans Louisiana Gas Company | Louisiana | PSC Staff | Rate of return |
| 122. | ER-91121820J<br>July 1992 | Jersey Central Power & Light Company | New Jersey | Rate Counsel | Rate of return |
| 123. | R-00922314<br>August 1992 | Metropolitan Edison Company | Pennsylvania | Office of Consumer Advocate | Rate of return |
| 124. | 92-049-05<br>September 1992 | US West Communications | Utah | Committee of Consumer Services | Rate of return |
| 125. | 92PUE0037<br>September 1992 | Commonwealth Gas Company | Virginia | Attorney General | Rate of return |
| 126. | EC92-21-000<br>September 1992 | Entergy Services, Inc. | FERC | Louisiana PSC | Merger Impacts<br>(Affidavit) |

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|---|---|---|---|---|---|
| 127. | ER92-341-000<br>December 1992 | System Energy Resources | FERC | Louisiana PSC | Rate of return |
| 128. | U-19904<br>November 1992 | Louisiana Power &<br>Light Company | Louisiana | Staff | Merger analysis, competition<br>competition issues |
| 129. | 8473<br>November 1992 | Baltimore Gas &<br>Electric Company | Maryland | Dept. of Natural<br>Resources | QF contract evaluation |
| 130. | IPC-E-92-25<br>January 1993 | Idaho Power Company | Idaho | Federal Executive<br>Agencies | Power supply<br>clause |
| 131. | E002/GR-92-1185<br>February 1993 | Northern States<br>Power Company | Minnesota | Attorney General | Rate of return |
| 132. | 92-102, Phase II<br>March 1992 | Central Maine<br>Power Company | Maine | Staff | QF contracts prudence and<br>procurements practices |
| 133. | EC92-21-000<br>March 1993 | Entergy Corporation | FERC | Louisiana PSC | Merger issues |
| 134. | 8489<br>March 1993 | Delmarva Power &<br>Light Company | Maryland | Dept. of Natural<br>Resources | Power plant certification |
| 135. | 11735<br>April 1993 | Texas Electric<br>Utilities Company | Texas | Federal Executives<br>Agencies | Rate of return |
| 136. | 2082<br>May 1993 | Providence Gas<br>Company | Rhode Island | Division of Public<br>Utilities | Rate of return |
| 137. | P-00930715<br>December 1993 | Bell Telephone Co.<br>of Pennsylvania | Pennsylvania | Office of Consumer<br>Advocate | Rate of return, financial<br>projections, Bell/TCI merger |
| 138. | R-00932670<br>February 1994 | Pennsylvania-American<br>Water Company | Pennsylvania | Office of Consumer<br>Advocate | Rate of return |
| 139. | 8583<br>February 1994 | Conowingo Power Co. | Maryland | Dept. of Natural<br>Resources | Competitive bidding<br>for power supplies |
| 140. | E-015/GR-94-001<br>April 1994 | Minnesota Power &<br>Light Co. | Minnesota | Attorney General | Rate of return |
| 141. | CC Docket No. 94-1<br>May 1994 | Generic Telephone | FCC | MCI Comm. Corp. | Rate of return |
| 142. | 92-345, Phase II<br>June 1994 | Central Maine Power Co. | Maine | Advocacy Staff | Price Cap Regulation<br>Fuel Costs |

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|---|---|---|---|---|---|
| 143. | 93-11065<br>April 1994 | Nevada Power Co. | Nevada | Federal Executive Agencies | Rate of return |
| 144. | 94-0065<br>May 1994 | Commonwealth Edison Co. | Illinois | Federal Executive Agencies | Rate of return |
| 145. | GR94010002J<br>June 1994 | South Jersey Gas Co. | New Jersey | Rate Counsel | Rate of return |
| 146. | WR94030059<br>July 1994 | New Jersey-American Water Co. | New Jersey | Rate Counsel | Rate of return |
| 147. | RP91-203-000<br>June 1994 | Tennessee Gas Pipeline Company | *FERC* | *Customer Group* | Environmental Externalities (oral testimony only) |
| 148. | ER94-998-000<br>July 1994 | Ocean State Power | FERC | Boston Edison Co. | Rate of return |
| 149. | R-00942986<br>July 1994 | West Penn Power Co. | Pennsylvania | Office of Consumer Advocate | Rate of return, emission allowances |
| 150. | 94-121<br>August 1994 | South Central Bell Telephone Co. | Kentucky | Attorney General | Rate of return |
| 151. | 35854-S2<br>November 1994 | PSI Energy, Inc. | Indiana | Utility Consumer Counsel | Merger savings and allocations |
| 152. | IPC-E-94-5<br>November 1994 | Idaho Power Co. | Idaho | Federal Executive Agencies | Rate of return |
| 153. | November 1994 | Edmonton Water | Alberta, Canada | Regional Customer Group | Rate of return (rebuttal only) |
| 154. | 90-256<br>December 1994 | South Central Bell Telephone Co. | Kentucky | Attorney General | Incentive Plan True-Ups |
| 155. | U-20925<br>February 1995 | Louisiana Power & Light Company | *Louisiana* | *PSC Staff* | Rate of return<br>Industrial contracts<br>Trust fund earnings |
| 156. | R-00943231<br>February 1995 | Pennsylvania-American Water Company | Pennsylvania | Consumer Advocate | Rate of return |
| 157. | 8678<br>March 1995 | Generic | Maryland | *Dept. Natural Resources* | Electric Competition<br>Incentive Regulation<br>(oral only) |

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|---|---|---|---|---|---|
| 158. | R-000943271<br>April 1995 | Pennsylvania Power & Light Company | Pennsylvania | Consumer Advocate | Rate of return<br>Nuclear decommissioning<br>Capacity Issues |
| 159. | U-20925<br>May 1995 | Louisiana Power & Light Company | Louisiana | Commission Staff | Class cost of service issues |
| 160. | 2290<br>June 1995 | Narragansett Electric Company | Rhode Island | Division Staff | Rate of return |
| 161. | U-17949E<br>June 1995 | South Central Bell Telephone Company | Louisiana | Commission Staff | Rate of return |
| 162. | 2304<br>July 1995 | Providence Water Supply Board | Rhode Island | Division Staff | Cost recovery of capital spending program |
| 163. | ER95-625-000 et al.<br>August 1995 | PSI Energy, Inc. | FERC | Office of Utility Consumer Counselor | Rate of return |
| 164. | P-00950915 et al.<br>September 1995 | Paxton Creek Cogeneration Assoc. | Pennsylvania | Office of Consumer Advocate | Cogeneration contract amendment |
| 165. | 8702<br>September 1995 | Potomac Edison Company | Maryland | Dept. of Natural Resources | Allocation of DSM Costs (oral only) |
| 166. | ER95-533-001<br>September 1995 | Ocean State Power | FERC | Boston Edison Co. | Cost of equity |
| 167. | 40003<br>November 1995 | PSI Energy, Inc. | Indiana | Utility Consumer Counselor | Rate of return<br>Retail wheeling |
| 168. | P-55, SUB 1013<br>January 1996 | BellSouth | North Carolina | AT&T | Rate of return |
| 169. | P-7, SUB 825<br>January 1996 | Carolina Tel. | North Carolina | AT&T | Rate of return |
| 170. | February 1996 | Generic Telephone | FCC | MCI | Cost of capital |
| 171. | 95A-531EG<br>April 1996 | Public Service Company of Colorado | Colorado | Federal Executive Agencies | Merger issues |
| 172. | ER96-399-000<br>May 1996 | Northern Indiana Public Service Company | FERC | Indiana Office of Utility Consumer Counselor | Cost of capital |
| 173. | 8716<br>June 1996 | Delmarva Power & Light Company | Maryland | Dept. of Natural Resources | DSM programs |

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|---|---|---|---|---|---|
| 174. | 8725<br>July 1996 | BGE/PEPCO | Maryland | Md. Energy Admin. | Merger Issues |
| 175. | U-20925<br>August 1996 | Entergy Louisiana, Inc. | Louisiana | PSC Staff | Rate of return<br>Allocations<br>Fuel Clause |
| 176. | EC96-10-000<br>September 1996 | BGE/PEPCO | FERC | Md. Energy Admin. | Merger issues<br>competition |
| 177. | EL95-53-000<br>November 1996 | Entergy Services, Inc. | FERC | Louisiana PSC | Nuclear Decommissioning |
| 178. | WR96100768<br>March 1997 | Consumers NJ Water Company | New Jersey | Ratepayer Advocate | Cost of Capital |
| 179. | WR96110818<br>April 1997 | Middlesex Water Co. | New Jersey | Ratepayer Advocate | Cost of Capital |
| 180. | U-11366<br>April 1997 | Ameritech Michigan | Michigan | MCI | Access charge reform/financial condition |
| 181. | 97-074<br>May 1997 | BellSouth | Kentucky | MCI | Rate Rebalancing financial condition |
| 182. | 2540<br>June 1997 | New England Power | Rhode Island | PUC Staff | Divestiture Plan |
| 183. | 96-336-TP-CSS<br>June 1997 | Ameritech Ohio | Ohio | MCI | Access Charge reform<br>Economic impacts |
| 184. | WR97010052<br>July 1997 | Maxim Sewerage Corp. | New Jersey | Ratepayer Advocate | Rate of Return |
| 185. | 97-300<br>August 1997 | LG&E/KU | Kentucky | Attorney General | Merger Plan |
| 186. | Case No. 8738<br>August 1997 | Generic<br>(oral testimony only) | Maryland | Dept. of Natural Resources | Electric Restructuring Policy |
| 187. | Docket No. 2592<br>September 1997 | Eastern Utilities | Rhode Island | PUC Staff | Generation Divestiture |
| 188. | Case No.97-247<br>September 1997 | Cincinnati Bell Telephone | Kentucky | MCI | Financial Condition |
| 189. | Docket No. U-20925<br>November 1997 | Entergy Louisiana | Louisiana | PSC Staff | Rate of Return |

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|---|---|---|---|---|---|
| 190. | Docket No. D97.7.90 November 1997 | Montana Power Co. | *Montana* | *Montana Consumers Counsel* | Stranded Cost |
| 191. | Docket No. EO97070459 November 1997 | Jersey Central Power & Light Co. | New Jersey | Ratepayer Advocate | Stranded Cost |
| 192. | Docket No. R-00974104 November 1997 | Duquesne Light Co. | Pennsylvania | Office of Consumer Advocate | Stranded Cost |
| 193. | Docket No. R-00973981 November 1997 | West Penn Power Co. | Pennsylvania | Office of Consumer Advocate | Stranded Cost |
| 194. | Docket No. A-1101150F0015 November 1997 | Allegheny Power System DQE, Inc. | Pennsylvania | Office of Consumer Advocate | Merger Issues |
| 195. | Docket No. WR97080615 January 1998 | Consumers NJ Water Company | New Jersey | Ratepayer Advocate | Rate of Return |
| 196. | Docket No. R-00974149 January 1998 | Pennsylvania Power Company | Pennsylvania | Office of Consumer Advocate | Stranded Cost |
| 197. | Case No. 8774 January 1998 | Allegheny Power System DQE, Inc. | Maryland | Dept. of Natural Resources MD Energy Administration | Merger Issues |
| 198. | Docket No. U-20925 (SC) March 1998 | Entergy Louisiana, Inc. | Louisiana | Commission Staff | Restructuring, Stranded Costs, Market Prices |
| 199. | Docket No. U-22092 (SC) March 1998 | Entergy Gulf States, Inc. | Louisiana | Commission Staff | Restructuring, Stranded Costs, Market Prices |
| 200. | Docket Nos. U-22092 (SC) and U-20925(SC) May 1998 | Entergy Gulf States and Entergy Louisiana | Louisiana | Commission Staff | Standby Rates |
| 201. | Docket No. WR98010015 May 1998 | NJ American Water Co. | New Jersey | Ratepayer Advocate | *Rate of Return* |
| 202. | Case No. 8794 December 1998 | Baltimore Gas & Electric Co. | Maryland | MD Energy Admin./Dept. Of Natural Resources | Stranded Cost/ *Transition Plan* |
| 203. | Case No. 8795 December 1998 | Delmarva Power & Light Co. | Maryland | MD Energy Admin./Dept. Of Natural Resources | Stranded Cost/ Transition Plan |
| 204. | Case No. 8797 January 1998 | Potomac Edison Co. | Maryland | MD Energy Admin./Dept. Of Natural Resources | Stranded Cost/ Transition Plan |

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|---|---|---|---|---|---|
| 205. | Docket No. WR98090795<br>March 1999 | Middlesex Water Co. | New Jersey | Ratepayer Advocate | Rate of Return |
| 206. | Docket No. 99-02-05<br>April 1999 | Connecticut Light & Power | Connecticut | Attorney General | Stranded Costs |
| 207. | Docket No. 99-03-04<br>May 1999 | United Illuminating Company | Connecticut | Attorney General | Stranded Costs |
| 208. | Docket No. U-20925 (FRP)<br>June 1999 | Entergy Louisiana, Inc. | Louisiana | Staff | Capital Structure |
| 209. | Docket No. EC-98-40-000<br>et. al.<br>May 1999 | American Electric Power/<br>Central & Southwest | FERC | Arkansas PSC | Market Power<br>Mitigation |
| 210. | Docket No. 99-03-35<br>July 1999 | United Illuminating Company | Connecticut | Attorney General | Restructuring |
| 211. | Docket No. 99-03-36<br>July 1999 | Connecticut Light & Power Co. | Connecticut | Attorney General | Restructuring |
| 212. | WR99040249<br>Oct. 1999 | Environmental Disposal Corp. | New Jersey | Ratepayer Advocate | Rate of Return |
| 213. | 2930<br>Nov. 1999 | NEES/EUA | Rhode Island | Division Staff | Merger/Cost of Capital |
| 214. | DE99-099<br>Nov. 1999 | Public Service New Hampshire | New Hampshire | Consumer Advocate | Cost of Capital Issues |
| 215. | *00-01-11*<br>Feb. 2000 | *Con Ed/NU* | Connecticut | Attorney General | Merger Issues |
| 216. | Case No. 8821<br>*May 2000* | Reliant/ODEC | Maryland | Dept. of Natural Resources | Need for Power/Plant Operations |
| 217. | Case No. 8738<br>July 2000 | Generic | Maryland | Dept. of Natural Resources | DSM Funding |
| 218. | Case No. U-23356<br>June 2000 | Entergy Louisiana, Inc. | Louisiana | PSC Staff | *Fuel Prudence Issues*<br>Purchased Power |
| 219. | Case No. 21453 et. al<br>July 2000 | SWEPCO | Louisiana | PSC Staff | Stranded Costs |

Expert Testimony
of Matthew I. Kahal

| | Docket Number | Utility | Jurisdiction | Client | Subject |
|---|---|---|---|---|---|
| 220. | Case No. 20925 (B)<br>July 2000 | Entergy Louisiana | Louisiana | PSC Staff | Purchase Power Contracts |
| 221. | Case No. 24889<br>August 2000 | Entergy Louisiana | Louisiana | PSC Staff | Purchase Power Contracts |
| 222. | Case No. 21453 et. al.<br>February 2001 | CLECO | Louisiana | PSC Staff | Stranded Costs |
| 223. | P-00001860<br>and P-0000181<br>March 2001 | GPU Companies | Pennsylvania | Office of Consumer Advocate | Rate of Return |
| 224. | CVOL-0505662-S<br>March 2001 | ConEd/NU | Connecticut Superior Court | Attorney General | Merger (Affidavit) |
| 225. | U-20925 (SC)<br>March 2001 | Entergy Louisiana | Louisiana | PSC Staff | Stranded Costs |
| 226. | U-22092 (SC)<br>March 2001 | Entergy Gulf States | Louisiana | PSC Staff | Stranded Costs |
| 227. | U-25533<br>May 2001 | Entergy Louisiana/<br>Gulf States | Louisiana<br>Interruptible Service | PSC Staff | Purchase Power |
| 228. | P-00011872<br>May 2001 | Pike County Pike | Pennsylvania | Office of Consumer Advocate | Rate of Return |
| 229. | 8893<br>July 2001 | Baltimore Gas & Electric Co. | Maryland | MD Energy Administration | Corporate Restructuring |
| 230. | 8890<br>September 2001 | Potomac Electric/Conectiv | Maryland | MD Energy Administration | Merger Issues |
| 231. | U-25533<br>August 2001 | Entergy Louisiana /<br>Gulf States | Louisiana | Staff | Purchase Power Contracts |
| 232. | U-25965<br>November 2001 | Generic | Louisiana | Staff | RTO Issues |
| 233. | 3401<br>March 2002 | New England Gas Co. | Rhode Island | Division of Public Utilities | Rate of Return |
| 234. | 99-833-MJR<br>April 2002 | Illinois Power Co. | U.S. District Court | U.S. Department of Justice | New Source Review |
| 235. | U-25533<br>March 2002 | Entergy Louisiana/<br>Gulf States | Louisiana | PSC Staff | Nuclear Uprates<br>Purchase Power |

Expert Testimony
of Matthew I. Kahal

| | Docket Number | Utility | Jurisdiction | Client | Subject |
|---|---|---|---|---|---|
| 236. | P-00011872<br>May 2002 | Pike County Power & Light | Pennsylvania | Consumer Advocate | POLR Service Costs |
| 237. | U-26361, Phase I<br>May 2002 | Entergy Louisiana/ Gulf States | Louisiana | PSC Staff | Purchase Power Cost Allocations |
| 238. | R-00016849C001 et al.<br>June 2002 | Generic | Pennsylvania | Pennsylvania OCA | Rate of Return |
| 239. | U-26361, Phase II<br>July 2002 | Entergy Louisiana/ Entergy Gulf States | Louisiana | PSC Staff | Purchase Power Contracts |
| 240. | U-20925(B)<br>August 2002 | Entergy Louisiana | Louisiana | PSC Staff | Tax Issues |
| 241. | U-26531<br>October 2002 | SWEPCO | Louisiana | PSC Staff | Purchase Power Contract |
| 242. | 8936<br>October 2002 | Delmarva Power & Lt. | Maryland | Energy Administration Dept. Natural Resources | Standard Offer Service |
| 243. | U-25965<br>November 2002 | SWEPCO/AEP | Louisiana | PSC Staff | RTO Cost/Benefit |
| 244. | 8908 Phase I<br>November 2002 | Generic | Maryland | Energy Administration Dept. Natural Resources | Standard Offer Service |
| 245. | 02S-315EG<br>November 2002 | Public Service Co. of Colorado | Colorado | Fed. Executive Agencies | Rate of Return |
| 246. | EL02-111-000<br>December 2002 | PJM/MISO | FERC | MD PSC | Transmission Ratemaking |
| 247. | 02-0479<br>February 2003 | Commonwealth Edison | Illinois | Dept. of Energy | POLR Service |
| 248. | PL03-1-000<br>March 2003 | Generic | FERC | NASUCA | Transmission Pricing (Affidavit) |
| 249. | U-27136<br>April 2003 | Entergy Louisiana | Louisiana | Staff | Purchase Power Contracts |
| 250. | 8908 Phase II<br>July 2003 | Generic | Maryland | Energy Admin. Dept. of Natural Resources | Standard Offer Service |
| 251. | U-27192<br>June 2003 | Entergy Louisiana and Gulf States | Louisiana | LPSC Staff | Purchase Power Contract Cost Recovery |

Expert Testimony
of Matthew I. Kahal

| | Docket Number | Utility | Jurisdiction | Client | Subject |
|---|---|---|---|---|---|
| 252. | C2-99-1181<br>October 2003 | Ohio Edison Co. | U.S. District Court | U.S. Department of Justice et. al. | Clean Air Act Compliance Economic Impact |
| 253. | RP03-398-000<br>December 2003 | Northern Natural Gas Co. | FERC | Municipal Distributors Group/Gas Task Force | Rate of Return |
| 254. | 8738<br>December 2003 | Generic | Maryland | Energy Admin Department of Natural Resources | Environmental Disclosure (oral only) |
| 255. | U-27136<br>December 2003 | Entergy Louisiana, Inc. | Louisiana | PSC Staff | Purchase Power Contracts |
| 256. | U-27192, Phase II<br>October/December 2003 | Entergy Louisiana & Entergy Gulf States | Louisiana | PSC Staff | Purchase Power Contracts |
| 257. | WC Docket 03-173<br>December 2003 | Generic | FCC | MCI | Cost of Capital |
| 258. | ER 030 20110<br>January 2004 | Atlantic City Electric | New Jersey | Ratepayer Advocate | Rate of Return |
| 259. | E-01345A-03-0437<br>January 2004 | Arizona Public Service Co. | Arizona | Federal Executive Agencies | Rate of Return |
| 260. | 03-10001<br>January 2004 | Nevada Power Co. | Nevada | U.S. Dept. of Energy | Rate of Return |
| 261. | R-00049255<br>June 2004 | PPL Elec. Utility | Pennsylvania | Office of Consumer Advocate | Rate of Return |

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) ) | DOCKET NO. R-00049255 |

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 2004

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

**PPL ELECTRIC UTILITIES CORPORATION**

Rate of Return Summary
(as of 12/31/04)

| Capital Type | Balance[(1)] (Millions) | Percent of Total | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Short-term debt | $ 0 | 0.00% | -- | -- |
| Long-term debt | 1,363[2] | 51.59 | 6.43[2] | 3.32 |
| Preferred Stock | 49 | 1.85 | 6.19[3] | 0.11 |
| Common Equity | 1,230[1] | 46.56 | 9.50[4] | 4.42 |
| Total | $ 2,642 | 100.0% | -- | 7.85% |

[1]Moul, Schedule 6, page 1.

[2]Moul, Schedule 7, page 2.

[3]Moul, Schedule 8, page 2.

[4]Schedule MIK-4, page 1. (Pre-tax interest coverage = 3.3x)

**PPL ELECTRIC UTILITIES CORPORATION**

Trends in Capital Costs

| | Annualized Inflation (CPI) | 10-Year Treasury Yield | 3-Month Treasury Yield | Single A Utility Yield |
|---|---|---|---|---|
| 1992 | 3.0% | 7.0% | 3.5% | 8.7% |
| 1993 | 3.0 | 5.9 | 3.0 | 7.6 |
| 1994 | 2.6 | 7.1 | 4.3 | 8.3 |
| 1995 | 2.8 | 6.6 | 5.5 | 7.9 |
| 1996 | 3.0 | 6.4 | 5.0 | 7.8 |
| 1997 | 2.3 | 6.4 | 5.1 | 7.6 |
| 1998 | 1.6 | 5.3 | 4.8 | 7.0 |
| 1999 | 2.2 | 5.7 | 4.7 | 7.6 |
| 2000 | 3.4 | 6.0 | 5.9 | 8.3 |
| 2001 | 2.9 | 5.0 | 3.5 | 7.8 |
| 2002 | 1.6 | 4.6 | 1.6 | 7.4 |
| 2003 | 1.9 | 4.1 | 1.0 | 6.6 |
| 2001 | | | | |
| January | 3.7% | 5.2% | 5.3% | 7.8% |
| February | 3.5 | 5.1 | 4.9 | 7.7 |
| March | 2.9 | 4.9 | 4.5 | 7.7 |
| April | 3.3 | 5.1 | 3.9 | 7.9 |
| May | 3.6 | 5.4 | 3.7 | 8.0 |
| June | 3.3 | 5.3 | 3.5 | 7.9 |
| July | 2.7 | 5.2 | 3.5 | 7.8 |
| August | 2.7 | 5.0 | 3.4 | 7.6 |
| September | 2.7 | 4.7 | 2.9 | 7.8 |
| October | 2.1 | 4.6 | 2.2 | 7.6 |
| November | 1.9 | 4.7 | 1.9 | 7.6 |
| December | 1.6 | 5.1 | 1.7 | 7.8 |

**PPL ELECTRIC UTILITIES CORPORATION**

Trends in Capital Costs (Continued)

| | Annualized Inflation (CPI) | 10-Year Treasury Yield | 3-Month Treasury Yield | Single A Utility Yield |
|---|---|---|---|---|
| 2002 | | | | |
| January | 1.1% | 5.0% | 1.7% | 7.7% |
| February | 1.1 | 4.9 | 1.7 | 7.5 |
| March | 1.5 | 5.3 | 1.8 | 7.8 |
| April | 1.6 | 5.2 | 1.7 | 7.6 |
| May | 1.2 | 5.2 | 1.7 | 7.5 |
| June | 1.1 | 4.9 | 1.7 | 7.4 |
| July | 1.5 | 4.7 | 1.7 | 7.3 |
| August | 1.8 | 4.3 | 1.6 | 7.2 |
| September | 1.5 | 3.9 | 1.6 | 7.1 |
| October | 2.0 | 3.9 | 1.6 | 7.2 |
| November | 2.2 | 4.1 | 1.3 | 7.1 |
| December | 2.4 | 4.0 | 1.2 | 7.1 |
| 2003 | | | | |
| January | 2.6% | 4.1% | 1.2% | 7.1% |
| February | 3.0 | 3.9 | 1.2 | 6.9 |
| March | 3.0 | 3.8 | 1.1 | 6.8 |
| April | 2.1 | 4.0 | 1.1 | 6.6 |
| May | 2.1 | 3.6 | 1.1 | 6.4 |
| June | 2.1 | 3.7 | 0.9 | 6.2 |
| July | 2.1 | 4.0 | 0.9 | 6.6 |
| August | 2.2 | 4.5 | 1.0 | 6.8 |
| September | 2.3 | 4.3 | 1.0 | 6.6 |
| October | 2.0 | 4.3 | 0.9 | 6.4 |
| November | 1.8 | 4.3 | 1.0 | 6.4 |
| December | 1.8 | 4.3 | 0.9 | 6.3 |
| 2004 | | | | |
| January | 1.9% | 4.2% | 0.9% | 6.2% |
| February | 1.7 | 4.1 | 0.9 | 6.2 |
| March | 1.7 | 3.8 | 0.9 | 6.0 |
| April | 2.3 | 4.4 | 0.9 | 6.4 |
| May | 3.1 | 4.7 | 1.0 | 6.7 |

Source: Economic Report of the President, Economic Indicators, Mergent's Bond Record, Federal Reserve Statistical Release.

**PPL ELECTRIC UTILITIES CORPORATION**

Risk Indicators for Electric Delivery Service
Proxy Group[1]

| | Safety | Beta | Common Equity Ratio[2] | Bond Rating |
|---|---|---|---|---|
| C.H. Energy | 1 | 0.80 | 57.4% | A2 |
| Central Vermont | 3 | 0.50 | 59.1 | -- |
| Consolidated Edison | 1 | 0.60 | 49.5 | A1 |
| Duquesne Light | 4 | 0.70 | 32.4 | Baa2 |
| Energy East | 2 | 0.80 | 36.2 | Baa2 |
| Green Mountain | 3 | 0.65 | 49.9 | Baa1 |
| Northeast Utilities | 3 | 0.70 | 33.5 | Baa2 |
| NSTAR | 1 | 0.70 | 35.7 | A1 |
| PEPCO Holdings | 3 | NA | 30.8 | A2 |
| UIL | 3 | 0.75 | 47.1 | A3 |
| Average | 2.6 | 0.69 | 43.2% | -- |

(1) Source: Value Line Investment Survey, June 4, 2004

(2) Based on estimated year-end 2003 common equity, and total debt and preferred, per Value Line.

(3) Moody's ratings per Bond Record, April 2004.

**PPL ELECTRIC UTILITIES CORPORATION**

DCF Summary for Electric
Utility Delivery Service Proxy Group[1]

| | | |
|---|---|---|
| (1) | Dividend Yield (January –June 2004)[2] | 4.86% |
| (2) | Adjusted Yield (4.86% x 1.02) | 5.0% |
| (3) | DCF Growth Rate | 3.5-4.5% |
| (4) | Flotation Adjustment | 0.00% |
| (5) | *Total Return* ((2) + (3) + (4)) | 8.5-9.5% |
| (6) | Midpoint | 9.00% |
| **(7)** | **Recommendation** | **9.50%** |

---

(1) DCF model: $K_e = D_o/P_o (1 + 0.5g) + g$, where

$K_e$ = cost of equity

$D_o$ = current annualized dividend

$P_o$ = current stock price

g = long-term dividend growth rate.

(2) Including Central Vermont and Green Mountain, the average dividend yield is 4.66 percent.

**PPL ELECTRIC UTILITIES CORPORATION**

Dividend Yields, January – June 2004

| | Company | Jan. | Feb. | Mar. | Apr. | May | June | Average |
|---|---|---|---|---|---|---|---|---|
| (1) | C.H. Energy | 4.7% | 4.4% | 4.4% | 4.7% | 4.7 % | 4.9% | 4.6% |
| (2) | Con Ed | 5.2 | 5.1 | 5.1 | 5.5 | 5.8 | 5.9 | 5.4 |
| (3) | Energy East | 4.4 | 4.3 | 4.1 | 4.4 | 4.4 | 4.4 | 4.3 |
| (4) | Duquesne | 5.3 | 5.5 | 5.1 | 5.3 | 5.2 | 5.2 | 5.3 |
| (5) | NU | 3.1 | 3.1 | 3.2 | 3.3 | 3.4 | 3.4 | 3.3 |
| (6) | NSTAR | 4.5 | 4.3 | 4.4 | 4.6 | 4.7 | 4.7 | 4.5 |
| (7) | PEPCO | 5.0 | 4.7 | 4.9 | 5.3 | 5.4 | 5.5 | 5.1 |
| (8) | UIL | 6.2 | 6.0 | 6.0 | 6.4 | 6.5 | 6.6 | 6.3 |
| | **Average** | **4.80%** | **4.68%** | **4.65%** | **4.94%** | **5.01%** | **5.08%** | **4.86%** |
| (9) | Central Vermont | 3.9 | 4.2 | 4.1 | 4.6 | 4.7 | 4.7 | 4.4 |
| (10) | Green Mountain | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.5 | 3.4 |
| | **Average** | **4.56%** | **4.49%** | **4.47%** | **4.75%** | **4.82%** | **4.88%** | **4.66%** |

Source: Standard & Poors Stock Guide, February –June 2004 editions. Figures are the reported month end dividend yields. June figure is as of June 15.

**PPL ELECTRIC UTILITIES CORPORATION**

Summary of Five-Year
Earnings Growth Rates

| | Company | First Call | Zacks | Value Line | S&P |
|---|---|---|---|---|---|
| (1) | C.H. Energy | NA | NA | 0.5% | NA |
| (2) | Consolidated Ed. | 2.5 | 2.8 | (1.5%) | 3% |
| (3) | Duquesne Light | 4.0 | 5.0 | 11.0 | 4 |
| (4) | Energy East | 4.0 | 4.7 | 1.0 | 5 |
| (5) | Northeast Utilities | 4.5 | 4.0 | 10.0 | 5 |
| (6) | NSTAR | 5.0 | 4.3 | 3.0 | 4 |
| (7) | PEPCO Holdings | 3.0 | 2.7 | 3.5 | 3 |
| (8) | UIL | 1.0 | 2.0 | (2.0) | 1 |
| | **Average** | **3.43%** | **3.64%** | **3.19%** | **3.57%** |

Sources: First Call and Zacks values are as of May 2004 per finance.yahoo.com and MSNMONEY.com. Value Line is June 4, 2004. S&P is per Earnings Guide (June 2004).

Note: Green Mountain and Central Vermont are followed only by Value Line. The five-year earnings growth rates are 7.5 percent for Central Vermont and 3.5 percent for Green Mountain, resulting in a Value Line 10-company average of 4.4 percent.

**PPL ELECTRIC UTILITIES CORPORATION**

Additional Value Line Growth Measures

| | Company | 2004-2008 Dividends | 2004-2008 Book Value | Retained Earnings |
|---|---|---|---|---|
| (1) | C.H. Energy | 0.0% | 1.0% | 2.0% |
| (2) | Consolidated Edison | 0.9 | 1.7 | 1.5 |
| (3) | Duquesne Light | 1.0 | 6.5 | 5.5 |
| (4) | Energy East | 3.6 | 2.7 | 2.5 |
| (5) | Northeast Utilities | 7.9 | 5.0 | 6.0 |
| (6) | NSTAR | 2.8 | 3.9 | 4.5 |
| (7) | PEPCO | 2.8 | 3.1 | 5.0 |
| (8) | UIL | 0.0 | (1.0) | 0.0 |
| (9) | Central Vermont | 4.1 | 3.7 | 4.5 |
| (10) | Green Mountain | 9.8 | 3.4 | 5.0 |
| | **Average** | **3.3%** | **3.0%** | **3.7%** |

Source: Value Line Investment Survey, June 4, 2004. Retained earnings growth is based on 2007-2009 estimates.

**PPL ELECTRIC UTILITIES CORPORATION**

Historical Five-Year Growth Rates
for Electric Utility Delivery Service
Proxy Group

| | Company | Earnings | Dividends | Book Value |
|---|---|---|---|---|
| (1) | C.H. Energy | (2.0)% | 0.5% | 2.0% |
| (2) | Central Vermont | 6.0 | 0.5 | 1.0 |
| (3) | Consolidated Edison | 0.5 | 1.0 | 2.0 |
| (4) | Duquesne Light | (18.5) | (0.5) | (16.5) |
| (5) | Energy East | 4.0 | 6.0 | 4.5 |
| (6) | Green Mountain | 14.5 | (16.5) | (2.5) |
| (7) | Northeast Utilities | -- | (1.0) | 0.5 |
| (8) | NSTAR | 4.5 | 2.5 | 2.5 |
| (9) | PEPCO Holdings | NA | NA | NA |
| (10) | UIL | -- | -- | 2.0 |
| | **Average** | **1.0%** | **(0.8)%** | **(0.5)%** |

Source: Value Line Investment Survey, June 4, 2004.

# PPL ELECTRIC UTILITIES CORPORATION

Capital Asset Pricing Model Analysis

## A. Model Specification

$K_e = RF + \beta (R_m - R_f)$, where:

$K_e$ = cost of equity

$R_f$ = return on risk free asset

$R_m$ = expected return on the stock market

$\beta$ = beta statistic (*non diversifiable risk*)

## B. Data Inputs

| | |
|---|---|
| Risk Free Return: | 3-month Treasury - 1.0%<br>long-term Treasury - 5.0 - 5.5% |
| Market Return: | 11-12% |
| Beta: | 0.69 (electric delivery service proxy group) |

## C. Model Calculations

| | |
|---|---|
| Low end: | $K_e = 5.00\% + 0.69\ (11\text{-}5.0) = 9.14\%$ |
| Upper end: | $K_e = 5.5\% + 0.69\ (12\text{-}5.5) = 9.99\%$ |
| Midpoint: | $K_e = 5.25\% + 0.69\ (11.5\text{-}5.25) = 9.56\%$ |

**PPL ELECTRIC UTILITIES CORPORATION**

Stock Market Returns Estimates

(1) **Value Line Appreciation Potential (per Moul)**

$K_e$ = 1.7% (yield) + 10.67% (median appreciation) = 12.4%

(Value Line, June 11, 2004, indicates 4-year median appreciation = 50%)

(2) **Ibbotson Associates Historical Returns**

$K_e$ = 6.6% + 5.25% = 11.85% (arithmetic mean);
$K_e$ = 5.0% + 5.25% = 10.25 (geometric mean)
(Moul, Schedule 14, page 6 of 6)

(3) **Ibbotson/Chen Supply Side Model**

$K_e$ = 5.9% + 5.25% = 11.15%

(Ibbotson/Chen estimate an arithmetic risk premium of 5.9% for stocks over the historical time period, 1926-2000, excluding effects of rising P/E ratios.)

(4) **Industrial Composite DCF**

$K_e$ = 1.6% + 8.50% = 10.1%

(Value Line Industrial Composite, March 19, 2004. Dividend yield is 1.6% and growth rate is 5.5% for projected earnings and 11.5% for 2006-2008 earnings retention growth. Averaging the 5.5% and 11.5% provides a growth rate of 8.5%.)

DOCUMENT

OCA STATEMENT NO. 3-S
8/10/04 tbg FC

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) | DOCKET NO. R-00049255 |

DOCKETED
AUG 18 2004

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 2004

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PA PUC
SECRETARY'S BUREAU

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
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| PPL ELECTRIC UTILITIES CORPORATION | ) ) | DOCKET NO. R-00049255 |

**SURREBUTTAL TESTIMONY OF MATTHEW I. KAHAL**

## I. PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this case by the Exeter Associates, Inc., an economic consulting firm. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS CASE?

A. Yes. In June 2004, I submitted testimony on behalf of the Office of Consumer Advocate (OCA), identified as OCA Statement No. 3, addressing the fair rate of return on jurisdictional rate base for PPL Electric Utilities Corporation (PPLEU or the Company). That testimony includes a statement of my qualifications.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. On July 25, 2004, Company witnesses Cannell and Moul submitted rebuttal testimony on rate of return issues. Ms. Cannell's testimony mostly discussed PPLEU's risk attributes, while Mr. Moul's rebuttal testimony focused on the analytic cost of capital quantification issues. My surrebuttal testimony responds to their rebuttal filings.

Q. AS A RESULT OF YOUR REVIEW OF THE REBUTTAL TESTIMONY, HAVE YOU MADE ANY CHANGES TO YOUR RECOMMENDATION ON FAIR RATE OF RETURN?

A. No. However, I stated in my Direct Testimony that my June 2004 dividend yields (employed in my Discounted Cash Flow (DCF) study) were preliminary and would be updated when the actual, month-ending values for that month become available. Attached to my surrebuttal testimony is updated Schedule MIK-4, page 2 and 5 which includes the new data. The change to the six-month average is extremely minor and has no material impact on my original DCF results. The update results produce a slight reduction in the proxy group dividend yield (for ten companies), from 4.66 to 4.63 percent, and excluding the two Vermont companies, the change is 4.86 to 4.83 percent. I continue to recommend a return on common equity (ROE) of 9.50 percent.

## II. REPLY TO WITNESS CANNELL

Q. WHAT ARGUMENTS DOES WITNESS CANNELL SET FORTH IN HER REBUTTAL TESTIMONY?

A. Ms. Cannell begins her testimony asserting that the OCA/Staff recommendations "represent a worst-case outcome" from the perspective of investment analysts. Similarly, Mr. Moul argues that investors would be "disappointed" with the OCA's recommendation. Ms. Cannell states that the Federal Reserve Board's (Fed) June 29, 2004 interest rate increase further argues for a higher return on equity (ROE) award. She believes the ROE award should be increased to take into account "accelerating interest rates" and the possibility of "mounting inflation."

The remainder of Ms. Cannell's testimony (pp. 5-13) discusses certain business risk factors originally raised in her direct testimony. This includes RTO-related risks, "bypass" or loss of sales risk and alleged Provider of Last Resort (POLR) risk. Since these issues were discussed extensively in my June 2004 Direct Testimony, I reply only briefly to the arguments in Ms. Cannell's rebuttal.

### A. The Alleged "Worst Case Scenario"

Q. DOES MS. CANNELL DEMONSTRATE THAT INVESTMENT ANALYSTS REGARD TO THE OCA/STAFF RECOMMENDATIONS AS A "WORST CASE SCENARIO?"

A. No, this appears to be a misinterpretation of an investor service report by Ms. Cannell. The OCA is recommending a rate increase of $115.6 million, including a return on equity of 9.5 percent. Ms. Cannell cites to a Morgan Stanley (M-S) report (pp. 2-3) that characterizes Staff/OCA recommendations as "more supportive than expected," and M-S goes on to estimate the increase in earnings (for PPL Corporation) that would result. M-S then states that its earnings increase estimate should be viewed as conservatively low

("worst case scenario") because a regulatory commission (the PAPUC in this case) probably would not award less than what Staff/OCA are recommending. M-S clearly views the Staff/OCA positions as a positive for PPL Corp investors, not a negative. This is why the report is titled "Raising Price Target, Ests on Regulatory Catalysts."

Q. MS. CANNELL ALSO POINTS TO INVESTOR EXPECTATIONS OF A ROE AWARD IN THIS CASE OF 10 TO 12 PERCENT. DOESN'T THIS SUGGEST THAT INVESTORS WOULD REGARD YOUR RECOMMENDATION AS "DISAPPOINTING?"

A. Undoubtedly, there is a range of opinion among investors concerning the potential outcomes of utility rate cases. For example, a report from Lehman Brothers last year (June 4, 2003) discussing electric utilities states:

> As mentioned, we believe the current low interest rate environment is likely to lead to more rate cases and lower allowed returns.
>
> We think that it is only a matter of time before we see rate case decisions with allowed ROEs in the 9.0 to 10.0 range (page 11).

Speculation on probable Commission ROE awards in investor service reports does little to help us with the task at hand—determining the cost of equity for a low-risk electric distribution utility. Either Ms. Cannell and Mr. Moul believe in cost-based regulation and the cost of capital standard, or they do not. The objective in this case should be to identify the market-required cost of equity through the use of objective analysis. The fair rate of return should not be based upon someone's assertion regarding what ROE award would "please" investors versus what award would "disappoint" investors. That should not be this Commission's ratemaking standard.

At the present time, what I can say with a high degree of certainty is that Mr. Moul's 11.5 percent would substantially exceed the award investors expect in this case.

This is because the Company was awarded 11.5 percent in 1995, and as Mr. Moul has acknowledged, utility bond interest rates have declined sharply since then – by more than 2 full percentage points. In addition, the Company's business risk has declined and equity investment tax treatment today is more favorable, further reducing the equity cost of capital.

Q. MS. CANNELL REFERS TO "THE CURRENT CLIMATE OF ACCELERATING INTEREST RATES" AND "MOUNTING INFLATION." DOES THIS SUPPORT THE HIGHER ROEs, AS SHE SUGGESTS?

A. No, based on current and recent marketing conditions, she greatly overstates the problem. Ms. Cannell is correct that at the end of June the Fed increased short-term interest rates by a modest 0.25 percent, from the extraordinarily low 1.00 percent to a slightly less extraordinarily low 1.25 percent. I also agree that over time short-term rates (which are at artificially low levels) are likely to increase further.

With respect to the utility cost of equity, long-term interest rates are far more on point. The following table shows the pattern of long-term interest rates for calendar 2003 and 2004 year to date. Long-term interest rates certainly have increased since the low point in March of this year, but are only modestly higher than levels prevailing at the beginning of this year. It is fair to describe long-term interest rates as moving within the narrow ranges of about 6.0 to 6.5 percent for single A utility bonds and 5.0 to 5.5 percent for 20-year Treasury bonds. The "climate of accelerating interest rates" is a possible scenario, but it hardly describes what is actually taking place. The sharp increase in capital costs that she assumes is merely speculation concerning what might happen.

**Table 1**

**Interest Rate Trends**

| Time Period | Single A Utility | 20-Year Treasury |
|---|---|---|
| 2003 | 6.58% | 4.96% |
| January 2004 | 6.15 | 5.01 |
| February | 6.15 | 4.94 |
| March | 5.97 | 4.72 |
| April | 6.35 | 5.16 |
| May | 6.62 | 5.46 |
| June | 6.46 | 5.45 |
| July | 6.25 (per Moul) | 5.24 |

Source: Mergent Bond Record, July 2004; Federal Reserve "Statistical Release"

Q. MR. MOUL CITES INTEREST RATE FORECASTS TO ARGUE FOR A HIGHER RATE OF RETURN. IS THIS REASONABLE?

A. Mr. Moul is correct that forecasts have been published predicting an increase next year in interest rates (although still far below the 1995 levels), and I have no problem in acknowledging such forecasts as a possible future scenario. These forecasts provide insight into potential market risks, and I have considered that in formulating my ROE recommendation.

Where I disagree with Mr. Moul is that one cannot simply take a published forecast and substitute it for observed, objective market data in performing a cost of capital study. For example, Mr. Moul proposes to use a 6.0 percent Treasury yield in his

rebuttal CAPM, instead of the actual market values of 5.0 to 5.5 percent. Mr. Moul may believe that next year Treasury bonds will be priced to yield 6.0 percent, but his opinion is irrelevant. The forecasts that he cites are readily available to investors, and investors still choose to price Treasury bonds to yield roughly 5.25 percent. If investors actually expect Treasury prices to fall significantly between now and 2005, then they would not be willing to purchase or hold those bonds today.[1]

For cost of capital purposes, it is imperative that we use actual, verifiable market data – not speculative forecasts that the market itself does not adopt.

Q. DOES THE FED EXPECT A SHARP UPSURGE IN INFLATION?

A. No. The Fed uses as its primary inflation measure the Personal Consumption Expenditure (PCE) "Core" Price Index (i.e., excluding food and energy). The Fed's outlook for the PCE is 1.75 to 2.0 percent in 2004 and 1.5 to 2.0 percent in 2005.[2] The Fed believes inflation is likely to remain both very low and quite stable through 2005, which helps explain the current very low cost of capital environment and the Fed's very modest interest rate increase in late June.

## B. Ms. Cannell's Risk Arguments

Q. DOES MS. CANNELL PROVIDE ANY PERSUASIVE NEW INFORMATION CONCERNING PPLEU'S INVESTMENT RISK?

A. No. Her rebuttal testimony reasserts her original positions and offers very little that is new. She does note that the Company absorbed $90 million of costs associated with its current POLR supply contract with PPL Energy Plus.

[1] An increase in interest rates means that bond prices must fall. An investor will not purchase a bond today at $100 if he believes he can buy it next year at $90.

[2] As reported in Business Week, August 2, 2004, "Chill Out: Inflation Is Still Pretty Tame."

Q. HOW DOES MS. CANNELL'S DISCUSSION OF PPLEU'S BUSINESS RISKS IN HER REBUTTAL TESTIMONY RELATE TO FAIR RATE OF RETURN IN THIS CASE?

A. At the outset, I agree with Ms. Cannell that PPLEU faces a variety of business risks associated with the provision of electric distribution service, although I would not single out Regional Transmission Organization (RTO) policy or POLR arrangements as being significant in that regard. The former pertains primarily to the transmission function,[3] and the POLR arrangement (which extends through the end of this decade) is extremely low risk, as verified by the credit rating agency reports. PPLEU is, of course, subject to (between rate case) sales or "bypass" risk, but I presented data in my Direct Testimony demonstrating this to be a far smaller exposure than when the Company was vertically integrated. This is because the potentially contestable industrial load accounts for a very much smaller portion of the Company's distribution revenue today as compared to the integrated service revenue in 1995.

PPLEU does face business risks for distribution service -- however diminished -- and for that reason should receive a return that compensates for risk. No one is recommending a risk free return (i.e., a Treasury security yield), and my 9.5 percent ROE fully compensates for those risks.

Mr. Moul, Staff witness Deardorff and I all have applied the DCF model to proxy groups of delivery service electric utility companies to develop a return recommendation for PPLEU's distribution investment. At issue is whether the business risks discussed by Ms. Cannell are greater for PPLEU than for these proxy companies. This is the crucial question because the DCF method automatically captures all business risks perceived by investors. Ms. Cannell attempts to show that risks exist, but there is nothing in her

[3] The fair rate of return for transmission is set by the FERC and is not part of this case.

rebuttal testimony stating or implying that these risks are greater for PPLEU than for the ten proxy companies used in this case. Whatever one's opinions regarding the significance of these risks, they are accounted for in my DCF results.

A secondary but less important question is whether PPLEU's distribution operations are less risky than the Company's fully integrated operations in 1995 when the Company faced an uncertain future of state and federal restructuring. This is clearly the case. In 1995, the Company faced an assortment of risks and uncertainties related to its generation assets including its massive investment in the Susquehanna Nuclear Station. Again, these risks were accounted for in the DCF studies done at that time.

Q. MS. CANNELL MENTIONS THE $90 MILLION PAYMENT THAT PPLEU ABSORBED ASSOCIATED WITH POLR SERVICE. IS THIS AN INVESTOR RISK TODAY?

A. No, it is not. The payment was voluntarily incurred by the Company at the inception of its current POLR supply contract with its unregulated affiliate as part of its obligation -- agreed to in a settlement -- to adhere to its POLR rate cap.[4] This is not a going forward risk and is therefore irrelevant to either the current cost of capital or the Company's financial posture. Investment risk and cost of capital are prospective concepts. If Ms. Cannell is implying that this $90 million payment incurred in the past should be considered as a rate case or rate of return element, I consider such a suggestion to be highly improper. PPLEU should not be permitted to recover any portion of that $90 million POLR-supply cost incurred in the past either directly or indirectly as a return increment on the distribution service rate base. While PPLEU's POLR risk exposure for the remainder of the decade appears to be minimal, generation supply risk increments are not part of the distribution cost of service.

[4] The $90 million payment is a transfer of funds between two wholly-owned affiliates of the same holding company. It therefore has no effect on shareholder wealth.

## III. REPLY TO WITNESS MOUL

Q. WHAT POINTS DOES MR. MOUL RAISE IN HIS REBUTTAL TESTIMONY?

A. In response to my testimony, Mr. Moul makes the following points:

(a) He defends the assumed increase in the 12/31/04 common equity balance as "reasonable" based in part on an improving profit picture for PPLEU.

(b) He claims that the OCA/Staff fail to recognize the increase in the cost of equity expected by investors, as evidenced by interest rate forecasts. (I have already addressed this issue in response to Ms. Cannell, and no further discussion is needed.)

(c) He defends the growth rate he used in his gas utility DCF, and he criticizes the DCF growth rate that I employed as ignoring dividend growth.

(d) Using a recent Value Line report, Mr. Moul highlights the risk problems currently facing East region electric utilities.

(e) Mr. Moul discusses the credit rating issues and the implications of the OCA's recommendation.

(f) Mr. Moul argues that investors expect the proxy companies to earn 10.4 percent on equity, which exceeds the 9.5 percent that I recommend.

(g) Mr. Moul attempts to defend his market/book adjustment, both the need for this adjustment and the accuracy of his calculations.

(h) Mr. Moul defends his use of a "size" adjustment adder in his CAPM. Also, he attempts to argue that the stock market rate of return (a CAPM input) exceeds 12 percent.

(i) Mr. Moul defends his historical risk premium study claiming that historical risk return and risk premia data are frequently cited by investor publications.

Q. DID MR. MOUL SUBMIT AN UPDATE COST OF CAPITAL STUDY?

A. No, he did not even though he obviously could have done so in his rebuttal testimony. I regard this omission as extremely important given the emphasis that he places in his rebuttal testimony on the alleged trend toward higher capital costs and the recent interest rate forecasts. If the current trends and recent changes in outlook are truly so crucial in this case, then he should have updated his studies, which are based on market data extending back to 2003.

**A. <u>Capital Structure</u>**

Q. MR. MOUL CLAIMS THAT THE COMPANY'S FORECAST OF AN *INCREASE IN RETAINED EARNINGS IS REASONABLE AND SHOULD BE* ACCEPTED. DO YOU AGREE?

A. No. I kept the retained earnings balance constant, for calendar 2004, even though the Company's actual balance has <u>fallen</u> the last two years. The assumption of an increase is unrealistic, speculative and cannot be verified. The increase is pure assertion on the part of Mr. Moul. Moreover, the Company's ratemaking equity ratio already is quite robust,

absent this proposed increase, stronger than both the DCF proxy group and the industry average.

The only new information offered by Mr. Moul is that PPLEU's earnings have been better this year than expected (which seems like an odd reason for increasing the rate increase award). But he also concedes that the dividend payments to the parent will occur largely in the last half of this year. Hence, there is no way to verify the claimed increase.

**B. <u>The DCF Growth Rate</u>**

Q. IN YOUR DIRECT TESTIMONY, YOU CRITICIZED MR. MOUL'S DCF GROWTH RATE ASSUMPTIONS AS BEING UNSUPPORTED. DID HE RESPOND?

A. Mr. Moul did respond to my criticism of his gas LDC proxy group study, but he failed to respond in any meaningful way to my critique of his electric utility DCF study. This is a crucial issue given this Commission's primary reliance on DCF evidence for setting the fair rate of return.

Q. HOW DOES MR. MOUL DEFEND HIS GAS DCF STUDY ?

A. Mr. Moul indicates a preference for his gas study over his electric study due to the "uncertainties" facing the electric industry and his proxy companies. This is a rather unconvincing argument on several grounds. First, if the electric industry faces unique issues (which it certainly does), then this argues strongly against using the "wrong" industry as the cost of equity proxy. Second, these "uncertainties" will be revealed in market data as either increases in dividend yields or higher betas. Investors are perfectly capable of sorting out the uncertainties and reflecting these issues in their market valuations. A DCF study of electric utilities is not an improper approach for PPLEU.

Q. HOW DOES MR. MOUL DEFEND HIS GAS LDC GROWTH RATE?

A. He defends his growth rate by claiming that it is "within the array of analysts' growth forecasts," (page 13), but he rejects (without explanation) the use of the average of such forecasts. Since an "array" can be quite large, Mr. Moul has told us nothing. He leaves unanswered the question of how he selected his growth rate assumption from this "array."

Of even greater importance, Mr. Moul fails to address the issue over how he selected the growth rate for his electric utility study. As I pointed out, his selected assumption is far greater than the published analyst earnings forecasts.

Q. MR. MOUL CRITICIZES YOUR DCF STUDY FOR FAILING TO ACCOUNT FOR PROJECTED DIVIDEND GROWTH. IS THIS AN ACCURATE CRITICISM?

A. No, it is both an inaccurate and strange criticism. I cite the dividend growth rates in my testimony and demonstrate that they (along with other evidence) support my selected growth rate range. Mr. Moul's suggestion that I should have relied primarily upon projected dividend growth is completely inconsistent with his own testimony (Direct, page 33) where he states: "the circumstance of the Electric Group and the Gas Group mandate that the greatest emphasis be placed upon projected earnings per share growth." That is precisely what I did and what Mr. Moul did not do. He selected a growth rate of 5.5 percent which is higher than the published forecasts would support.

Q. MR. MOUL JUSTIFIES ASSUMING A HIGHER GROWTH RATE DUE TO CYCLICALLY DEPRESSED CONDITIONS. DOES THIS SUPPORT A GROWTH RATE HIGHER THAN FORECAST?

A. No, it does not. Mr. Moul has a valid point concerning cyclically depressed conditions in the recent past (e.g., 2001-2003). However, a moderate to strong economic recovery is occurring at this time, and the current outlook is for continued economic recovery for the next several years. Mr. Moul has a good argument for not relying on the historical

growth rates (which I do not), but this does not argue for going outside the projected earnings growth rates.

Q. IS THE PROJECTED PROXY GROUP DIVIDEND GROWTH RATE 5.5 PERCENT, AS MR. MOUL CLAIMS?

A. No, it is not. Table 2 below presents the 2004 to 2008 (the midpoint of 2007-2009) dividend growth rates from Value Line for the proxy group companies.

**Table 2**
**Value Line Dividend Growth Rates**

| Company | 2004 Dividend | 2008 Dividend | Calculated Growth Rate |
|---|---|---|---|
| C.H. Energy | $2.16 | $2.16 | 0.0% |
| Consolidated Ed | 2.26 | 2.34 | 0.9 |
| Duquesne Light | 1.00 | 1.04 | 1.0 |
| Energy East | 1.04 | 1.20 | 3.6 |
| Northeast | 1.40 | 2.15 | 7.9 |
| NSTAR | 2.24 | 2.50 | 2.8 |
| PEPCO | 1.02 | 1.14 | 2.8 |
| UIL | 2.88 | 2.88 | 0.0 |
| Central Vt. | 0.92 | 1.08 | 4.1 |
| Green Mountain | 0.88 | 1.28 | 9.8 |
| **Average** | --- | --- | **3.3%** |

Source: Value Line Investment Survey, June 4, 2004

The average is 3.3 percent, not 5.5 percent as Mr. Moul erroneously claims. There are two main problems with his calculations on page 17 of his rebuttal testimony. First, he inexplicably omits two companies for whom Value Line is projecting flat dividends (UIL and C.H. Energy), although he retains the two companies on his data

table on page 17. Had he retained those two companies, his growth rate average would be 4.4 percent -- not 5.5 percent.

The second problem is that he cites a PEPCO growth rate of 16 percent, whereas the growth rate outlook for that company is about 3 percent. This appears to be a data problem associated with the merger between PEPCO and Conectiv which closed in late in 2002, resulting in the formation of PEPCO Holdings. Value Line reports dividends of $0 in 2001, $0.42 in 2002 and $1.00 in 2003. Since the growth rate that Mr. Moul reports is based on a "base year" of 2001 to 2003 average, the 16 percent figure is artificially inflated. The growth rate of 16 percent is incorrect because the 2001 and 2002 (pre merger) dividend figures are incorrect. Moreover, the dividend growth rate relevant to the investor is the 2004 going forward value, and that is 2.8 percent, not 16 percent. The corrected dividend growth rate data fully support my DCF estimate and contradict Mr. Moul's DCF growth rate assumption.

Q. MR. MOUL CITES TO RECENT VALUE LINE COMMENTS ON THE EAST REGION ELECTRIC UTILITIES (PAGE 13). DOES THIS HELP SUPPORT A HIGHER RATE OF RETURN AWARD?

A. No. The cited language indicates that Value Line expects low returns on investment for these companies. It also discusses rising power supply costs and problems of excessive capacity in generation markets. PPLEU is fully protected from rising power supply costs, and excess capacity is a problem for unregulated merchants, not regulated delivery service. The Value Line discussion mentions cost pressures from employee benefits and reliability expenditures which could also impair margins for companies "operating under electricity price caps." PPLEU, of course, is no longer subject to a distribution price cap.

Q. MR. MOUL CITES VALUE LINE PROJECTIONS INDICATING THAT INVESTORS EXPECT THE PROXY COMPANIES TO EARN 10.4 PERCENT.

IS THIS INCONSISTENT WITH YOUR 9.5 PERCENT RECOMMENDATION?

A. No, my 9.5 percent is an estimate of the expected market return, and that can differ from the accounting returns that Mr. Moul cites. It appears that Mr. Moul is referring to Value Line's estimate of 2007-2009 earnings, and he is equating that to "investor expectations" of future profitability.

Table 3 below provides the profitability estimates for the proxy companies that Mr. Moul mentions on page 16 of his testimony.

**Table 3**

**2007-2009 Projected ROEs per Value Line**

| | | | |
|---|---|---|---|
| C.H. Energy | 8.5% | Green Mountain | 10.5% |
| Central Vt. | 9.5 | Northeast | 9.5 |
| Con Ed | 8.5 | NSTAR | 13.0 |
| Duquesne | 16.0 | PEPCO | 11.0 |
| Energy East | 8.5 | UIL | 8.5 |
| | **Average: 10.35%** | | |

As this table indicates, five of the ten companies are projected to earn 9.5 percent or less and only two companies are projected to earn more than 11 percent. This hardly supports Mr. Moul's position.

What stands out from this table is Duquesne's 16 percent ROE, and without Duquesne the group average ROE is 9.7 percent. The 16 percent for Duquesne is not due to expected strong earnings (the projected earnings in 2007-2009 is only $1.60 per share or less than Duquesne's earnings every year prior to 2000). Rather, the 16 percent ROE results from a very low equity base caused by accounting write offs. Value Line projects

that book value per share in 2007-2009 will be 40 percent less than in 2000, which is the true cause of Duquesne's very high ROE. Mr. Moul overlooks the crucial underlying facts and circumstances in presenting these ROE estimates.

## C. The Leverage Adjustment

Q. HOW DOES MR. MOUL DEFEND HIS LEVERAGE ADJUSTMENT FROM YOUR CRITICISMS?

A. With respect to whether the adjustment is needed at all, he claims that the adjustment is appropriate in order,

> to make the DCF results relevant in the ratemaking context, [and] market-derived cost rate cannot be used without modification (page 17)

This is a clear and candid admission on his part that the leverage adjustment is extraneous and not part of either the "DCF results" or "the market-derived cost rate." Rather, he argues that it is needed to make the DCF results "relevant."

In my opinion and that of the vast majority of DCF practitioners, this ad hoc adjustment is not needed to make the DCF results "relevant." Its purpose is merely to provide shareholders with additional compensation beyond that required by the market.

Mr. Moul's other argument concerns the accuracy of his quantification. He claims that the market capitalization data that he used are accurate and are based on reported FAS 107 data. He also claims that I have supplied no "proof" that the inclusion of short-term debt would alter the results. (page 18)

Q. HOW DO YOU RESPOND?

A. Even if one could accept Mr. Moul's conceptual argument, he applied his adjustment incorrectly. I did not question his quantification of the proxy group market capital structure, other than his erroneous omission of short-term debt. I stated that the Miller-Modigliani equations that he uses do not allow such an exclusion, and Mr. Moul did not

dispute that. Apparently, his only complaint is that I did not "prove" that short-term debt is present.

Table 4 below provides the total versus long-term debt as reported by Value Line for the proxy companies. This shows that short-term debt is present and that Mr. Moul, therefore, has understated the proxy group debt ratio.

**Table 4**
**Total Versus Long-Term Debt**
**(Millions)**

| Company | Total Debt | Long-Term Debt | Long-Term/Total |
|---|---|---|---|
| C.H. Energy | $300.9 | $285.9 | 95.0% |
| Central Vt. | 137.3 | 137.2 | 100.0 |
| Con Ed | 7,058.0 | 6,733.0 | 95.4 |
| Duquesne | 1,022.5 | 932.3 | 91.2 |
| Energy East | 4,333.5 | 3,997.8 | 92.3 |
| Green Mt. | 97.9 | 97.9 | 100.0 |
| Northeast | 4,325.0 | 4,247.0 | 98.2 |
| NSTAR | 2,451.7 | 1,982.5 | 80.9 |
| PEPCO | 7,035.0 | 5,299.9 | 75.3 |
| UIL | 597.4 | 495.5 | 82.9 |
| Average | | | **91.1%** |

Source: Value Line Investment Survey, June 4, 2004

According to this table, nearly 10 percent of the total debt of the proxy companies is short-term debt, and thus its arbitrary omission (contrary to financial theory) understates the amount of leverage actually present in the proxy group market-based capital structure that Mr. Moul uses for his leverage adjustment.

Mr. Moul, however, totally ignored the most serious error in his adjustment calculation that I pointed out in my Direct Testimony. He failed to even consider PPLEU's capital structure in computing his adjustment even though the stated purpose of his adjustment is to recognize that the "book" capital structure is being used for ratemaking. We are using PPLEU's "book" capital structure for ratemaking in this case, not the proxy group's book capital structure. Mr. Moul (page 18) tries to rationalize this error by claiming that PPLEU should have a higher equity ratio due to its allegedly higher risk. This appears to be an after-the-fact rationalization because he never previously claimed that PPLEU had greater business or investment risk than the proxy group companies, nor did he even offer that as a reason for ignoring PPLEU's "ratemaking" capital structure in performing his adjustment.

**D. <u>The Capital Asset Pricing Model Study</u>**

Q. WHAT ISSUES DOES MR. MOUL RAISE ON REBUTTAL CONCERNING THE CAPM STUDY?

A. Mr. Moul makes three points:

- The risk-free rate should be 6.0 percent based on recent forecasts;
- He defends his inclusion of a "size" adjustment of 0.82 percentage points; and
- He attempts to argue that the market return may be somewhat higher than 12 percent.

Earlier in this testimony I responded to Mr. Moul's erroneous notion that published forecasts should substitute for verifiable market data.

Q. WHY IS THE SIZE ADJUSTMENT IMPROPER?

A. In addition to the fact that Mr. Moul has failed to show that size is a unique risk factor for electric utilities that must be singled out, he fails to understand that it is already fully accounted for in the CAPM analysis. Mr. Moul employs an electric utility proxy group

and uses the average beta from that group for CAPM purposes. I have followed the same procedure. If size is a (non-diversifiable) risk factor at all, it would be automatically captured in the published beta statistics for these companies and therefore embodied in the CAPM results. No additional risk adjustment is needed, and in fact, such an adjustment would double count risk.

This raises the question as to whether PPL (or PPLEU) is smaller or larger than the proxy group companies. According to Value Line data, only one proxy company (Con Ed) is considered "large cap." Five of the companies are "mid cap," and four are listed by Value Line as "small cap." As I previously stated, as a stand-alone company PPLEU would be considered "mid cap," and thus it is larger than the average proxy group company. Hence, there is no basis for a separate "size" adjustment adder in the CAPM analysis, even if one assumes that size is a risk factor.

Q. MR. MOUL ARGUES THAT INVESTOR EXPECTED EARNINGS GROWTH SUPPORTS A MARKET RETURN EXCEEDING 12 PERCENT. IS THAT CORRECT?

A. No. According to the Zack's survey (July 28, 2004), the projected five-year growth rate in earnings for the S&P 500 is 10 percent. Since the S&P 500 dividend yield is about 1.7 percent, this implies a total return of less than 12 percent (about 11.8 percent), consistent with my stated range of 11 to 12 percent.[5] However, as Mr. Moul points out, Blue Chip forecasts corporate profits growth on a long-term basis of about 7 percent (March 10, 2004), and thus even the 11.8 percent rate of return may be too high.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does. 00080466

[5] The 11 to 12 percent range may reflect the cost of capital for non-regulated corporations. The cost rate for electric utility distribution operations would, of course, be far less.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| PPL ELECTRIC UTILITIES CORPORATION | ) ) | DOCKET NO. R-00049255 |

SCHEDULES ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 2004

EXETER

ASSOCIATES, INC.

5565 Sterrett Place

Suite 310

Columbia, Maryland 21044

**PPL ELECTRIC UTILITIES CORPORATION**

Dividend Yields, January – June 2004

| | Company | Jan. | Feb. | Mar. | Apr. | May | June | Average |
|---|---|---|---|---|---|---|---|---|
| (1) | C.H. Energy | 4.7% | 4.4% | 4.4% | 4.7% | 4.7 % | 4.7% | 4.6% |
| (2) | Con Ed | 5.2 | 5.1 | 5.1 | 5.5 | 5.8 | 5.7 | 5.4 |
| (3) | Energy East | 4.4 | 4.3 | 4.1 | 4.4 | 4.4 | 4.3 | 4.3 |
| (4) | Duquesne | 5.3 | 5.5 | 5.1 | 5.3 | 5.2 | 5.2 | 5.3 |
| (5) | NU | 3.1 | 3.1 | 3.2 | 3.3 | 3.4 | 3.3 | 3.2 |
| (6) | NSTAR | 4.5 | 4.3 | 4.4 | 4.6 | 4.7 | 4.6 | 4.5 |
| (7) | PEPCO | 5.0 | 4.7 | 4.9 | 5.3 | 5.4 | 5.5 | 5.1 |
| (8) | UIL | 6.2 | 6.0 | 6.0 | 6.4 | 6.5 | 5.9 | 6.2 |
| | **Average** | **4.80%** | **4.68%** | **4.65%** | **4.94%** | **5.01%** | **4.90%** | **4.83%** |
| (9) | Central Vermont | 3.9 | 4.2 | 4.1 | 4.6 | 4.7 | 4.5 | 4.3 |
| (10) | Green Mountain | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| | **Average** | **4.56%** | **4.49%** | **4.47%** | **4.75%** | **4.82%** | **4.71%** | **4.63%** |

Source: Standard & Poors Stock Guide, February –July 2004 editions. Figures are the reported month end dividend yields.

Pennsylvania Public Utility Commission, et al
v.
PPL Electric Utilities Corporation

Docket No. R-00049255

OCA Cross Examination Exhibit No. 1

Dated Entered: 8/10/04
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