

PPL ELECTRIC UTILITIES CORPORATION

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant .
P. Moul & Associates

Concerning

Cost of Capital

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE
2 AND QUALIFICATIONS

3 I was awarded a degree of Bachelor of Science in Business Administration by Drexel
4 University in 1971. While at Drexel, I participated in the Cooperative Education Program
5 which included employment, for one year, with American Water Works Service Company,
6 Inc., as an internal auditor, where I was involved in the audits of several operating water
7 companies of the American Water Works System and participated in the preparation of annual
8 reports to regulatory agencies and assisted in other general accounting matters.

9 Upon graduation from Drexel University, I was employed by American Water Works
10 Service Company, Inc., in the Eastern Regional Treasury Department where my duties included
11 preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility
12 for various treasury functions of the thirteen New England operating subsidiaries.

13 In 1973, I joined the Municipal Financial Services Department of Betz Environmental
14 Engineers, a consulting engineering firm, where I specialized in financial studies for municipal
15 water and wastewater systems.

16 In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I
17 held various positions with the Utility Services Group of AUS Consultants, concluding my
18 employment there as a Senior Vice President.

19 In 1994, I formed P. Moul & Associates, an independent financial and regulatory
20 consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I
21 have continuously studied the rate of return requirements for cost of service regulated firms. In
22 this regard, I have supervised the preparation of rate of return studies which were employed in
23 connection with my testimony and in the past for other individuals. I have presented direct

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1 testimony on the subject of fair rate of return, evaluated rate of return testimony of other
2 witnesses, and presented rebuttal testimony.

3 My studies and prepared direct testimony have been presented before thirty (30) federal,
4 state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory
5 Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida,
6 Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts,
7 Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina,
8 Ohio, Oklahoma, Tennessee, Pennsylvania, South Carolina, Texas, Virginia, and West
9 Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200
10 rate cases involving electric power, natural gas distribution and transmission, resource
11 recovery, solid waste collection and disposal, telephone, wastewater, and water service utility
12 companies. While my testimony has involved principally fair rate of return and financial
13 matters, I have also testified on capital allocations, capital recovery, cash working capital,
14 income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My
15 testimony has been offered on behalf of municipal and investor-owned public utilities and for
16 the staff of a regulatory commission. I have also testified at an Executive Session of the State
17 of New Jersey Commission of Investigation concerning the BPU regulation of solid waste
18 collection and disposal.

19 I was a co-author of a verified statement submitted to the Interstate Commerce
20 Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-
21 author of comments submitted to the Federal Energy Regulatory Commission regarding the
22 Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986
23 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000).
24 Further, I have been the consultant to the New York Chapter of the National Association of

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1 Water Companies which represented the water utility group in the Proceeding on Motion of the
2 Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-
3 0509). I have also submitted comments to the Federal Energy Regulatory Commission in its
4 Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission
5 Organizations and on behalf of the Edison Electric Institute in its intervention in the case of
6 Southern California Edison Company (Docket No. ER97-2355-000).

7 In late 1978, I arranged for the private placement of bonds on behalf of an investor-
8 owned public utility. I have assisted in the preparation of a report to the Delaware Public
9 Service Commission relative to the operations of the Lincoln and Ellendale Electric Company.
10 I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and
11 disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and
12 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection
13 Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

14 I have been a consultant to the Bucks County Water and Sewer Authority concerning
15 rates and charges for wholesale contract service with the City of Philadelphia. My municipal
16 consulting experience also included an assignment for Baltimore County, Maryland, regarding
17 the City/County Water Agreement for Metropolitan District customers (Circuit Court for
18 Baltimore County in Case 34/153/87-CSP-2636).

19 I am a member of the Society of Utility and Regulatory Financial Analysis (formerly
20 the National Society of Rate of Return Analysts) and have attended several Financial Forums
21 sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-
22 Wythe School of Law, College of William and Mary. I also attended an Executive Seminar
23 sponsored by the Colgate Darden Graduate Business School of the University of Virginia
24 concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October

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1 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings,
 2 and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

3 My lecture and speaking engagements include:

4	<u>Date</u>	<u>Occasion</u>	<u>Sponsor</u>
5			
6	April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory
7			Financial Analysts
8	December 2000	Pennsylvania Public Utility	Pennsylvania Bar Institute
9		Law Conference:	
10		Non-traditional Players	
11		in the Water Industry	
12	July 2000	EEI Member Workshop	Edison Electric Institute
13		Developing Incentives Rates:	
14		Application and Problems	
15	February 2000	The Sixth Annual	Exnet and Bruder, Gentile &
16		FERC Briefing	Marcoux, LLP
17	March 1994	Seventh Annual	Electric Utility
18		Proceeding	Business Environment Conf.
19	May 1993	Financial School	New England Gas Assoc.
20	April 1993	Twenty-Fifth	National Society of Rate
21		Financial Forum	of Return Analysts
22	June 1992	Rate and Charges	American Water Works
23		Subcommittee	Association
24		Annual Conference	
25	May 1992	Rates School	New England Gas Assoc.
26	October 1989	Seventeenth Annual	Water Committee of the
27		Eastern Utility	National Association
28		Rate Seminar	of Regulatory Utility
29			Commissioners Florida
30			Public Service Commission
31			and University of Utah
32	October 1988	Sixteenth Annual	Water Committee of the
33		Eastern Utility	National Association
34		Rate Seminar	of Regulatory Utility
35			Commissioners, Florida
36			Public Service
37			Commission and University
38			of Utah
39	May 1988	Twentieth Financial	National Society of
40		Forum	Rate of Return Analysts
41	October 1987	Fifteenth Annual	Water Committee of the
42		Eastern Utility	National Association
43		Rate Seminar	of Regulatory Utility
44			Commissioners, Florida

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1			Public Service Commis-
2			sion and University of
3			Utah
4	September 1987	Rate Committee	American Gas Association
5		Meeting	
6	May 1987	Pennsylvania	National Association of
7		Chapter	Water Companies
8		annual meeting	
9	October 1986	Eighteenth	National Society of Rate
10		Financial	of Return
11		Forum	
12	October 1984	Fifth National	American Bar Association
13		on Utility	
14		Ratemaking	
15		Fundamentals	
16	March 1984	Management Seminar	New York State Telephone
17			Association
18	February 1983	The Cost of Capital	Temple University, School
19		Seminar	of Business Admin.
20	May 1982	A Seminar on	New Mexico State
21		Regulation	University, Center for
22		and The Cost of	Business Research
23		Capital	and Services
24	October 1979	Economics of	Brown University
25		Regulation	

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RATESETTING PRINCIPLES

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2 Under traditional cost of service regulation, an agency engaged in ratesetting, such as
3 the Commission, serves as a substitute for competition. In setting rates, a regulatory agency
4 must carefully consider the public's interest in reasonably priced, as well as safe and reliable,
5 service. The level of rates must also provide an opportunity to earn a rate of return for the
6 public utility and its investors that is commensurate with the risk to which the invested capital
7 is exposed so that the public utility has access to the capital required to meet its service
8 responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public
9 utility will be unable to attract sufficient capital required to meet its responsibilities over time.

10 *It is important to remember that regulated firms must compete for capital in a global*
11 *market with non-regulated firms, as well as municipal, state and federal governments.*
12 *Traditionally, a public utility has been responsible for providing a particular type of service to*
13 *its customers within a specific market area. Although this relationship with its customers has*
14 *been changing, it remains quite different from a non-regulated firm which is free to enter and*
15 *exit competitive markets in accordance with available business opportunities.*

16 As established by the landmark Bluefield and Hope cases,¹ several tests must be
17 satisfied to demonstrate the fairness or reasonableness of the rate of return. These tests include
18 a determination of whether the rate of return is (i) similar to that of other financially sound
19 businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the
20 financial integrity of the public utility, and (iii) adequate to maintain and support the credit of
21 the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to

¹ Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and
F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

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1 *satisfy its capital requirements so that it can meet the obligation to provide adequate and*
2 *reliable service to the public.*

3 A fair rate of return must not only provide the utility with the ability to attract new
4 capital, it must also be fair to existing investors. An appropriate rate of return which may have
5 been reasonable at one point in time may become too high or too low at a subsequent point in
6 time, based upon changing business risks, economic conditions and alternative investment
7 opportunities. When applying the standards of a fair rate of return, it must be recognized that
8 the end result must provide for the payment of interest on the company's debt, the payment of
9 dividends on the company's stock, the recovery of costs associated with securing capital, the
10 maintenance of reasonable credit quality for the company, and support of the company's
11 financial condition, which today would include those measures of financial performance in the
12 areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

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EVALUATION OF RISK

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2 The rate of return required by investors is directly linked to the perceived level of risk.
3 The greater the risk of an investment, the higher is the required rate of return necessary to
4 compensate for that risk all else being equal. Because investors will seek the highest rate of
5 return available, considering the risk involved, the rate of return must at least equal the
6 investor-required, market-determined cost of capital if public utilities are to attract the
7 necessary investment capital on reasonable terms.

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In the measurement of the cost of capital, it is necessary to assess the risk of a firm.
9 The level of risk for a firm is often defined as the uncertainty of achieving expected
10 performance, and is sometimes viewed as a probability distribution of possible outcomes.
11 Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a
12 consequence, high risk firms must offer investors higher returns than low risk firms which pay
13 less to attract capital from investors. This is because the level of uncertainty, or risk of not
14 realizing expected returns, establishes the compensation required by investors in the capital
15 markets. Of course, the risk of a firm must also be considered in the context of its ability to
16 actually experience adequate earnings which conform with a fair rate of return. Thus, if there is
17 a high probability that a firm will not perform well due to fundamentally poor market
18 conditions, investors will demand a higher return.

19

 The investment risk of a firm is comprised of its business risk and financial risk.
20 Business risk is all risk other than financial risk, and is sometimes defined as the staying power
21 of the market demand for a firm's product or service and the resulting inherent uncertainty of
22 realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating
23 factors, e.g., productivity, competition, management ability, etc. that bear upon the expected

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1 pre-tax operating income attributed to the fundamental nature of a firm's business. Financial
2 risk results from a firm's use of borrowed funds (or similar sources of capital with fixed
3 payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ
4 financial leverage by borrowing any capital, its investment risk would be represented by its
5 business risk.

6 It is important to note that in evaluating the risk of regulated companies, financial
7 leverage cannot be considered in the same context as it is for non-regulated companies.
8 Financial leverage has a different meaning for regulated firms than for non-regulated
9 companies. For regulated public utilities, the cost of service formula gives the benefits of
10 financial leverage to consumers in the form of lower revenue requirements. For non-regulated
11 companies, all benefits of financial leverage are retained by the common stockholder.
12 Although retaining none of the benefits, regulated firms bear the risk of financial leverage.
13 Therefore, a regulated firm's rate of return on common equity must recognize the greater
14 financial risk shown by the higher leverage typically employed by public utilities.

15 Although no single index or group of indices can precisely quantify the relative
16 investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For
17 example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded,
18 the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a
19 stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other
20 indicators, which are reflective of business risk, include the variability of the rate of return on
21 equity, which is indicative of the uncertainty of actually achieving the expected earnings;
22 operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and
23 taxes other than income tax), which are indicative of profitability; the quality of earnings,

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- 1 which considers the degree to which earnings are the product of accounting principles or cost
- 2 deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital
- 3 in a company's capitalization is the measure of financial risk which is often analyzed in the
- 4 context of the equity ratio (i.e., the complement of the debt ratio).

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COST OF EQUITY--GENERAL APPROACH

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2 Through a fundamental financial analysis, the relative risk of a firm must be established
3 prior to the determination of its cost of equity. Any rate of return recommendation which lacks
4 such a basis will inevitably fail to provide a utility with a fair rate of return except by
5 coincidence. With a fundamental risk analysis as a foundation, standard financial models can
6 be employed by using informed judgment. The methods which have been employed to
7 measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk
8 Premium ("RP") approach, the Capital Asset Pricing Models ("CAPM") and the Comparable
9 Earnings ("CE") approach.

10 The traditional DCF model, while useful in providing some insight into the cost of
11 equity, is not an approach that should be used exclusively. The divergence of stock prices from
12 company-specific fundamentals can provide a misleading cost of equity calculation. As
13 reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman
14 Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to
15 earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was
16 attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a
17 model, such as DCF, which is founded upon identification of specific variables to explain stock
18 price growth. That is to say, when stock price growth exceeds growth in a company's earnings
19 per share, models such as DCF will misspecify investor expected returns which are comprised
20 of capital gains, as well as dividend receipts. As such, a combination of methods should be
21 used to measure the cost of equity.

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1 The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e.,
2 the yield that the public utility must offer to raise long-term debt capital directly from investors.
3 To that yield must be added a risk premium in recognition of the greater risk of common equity
4 over debt. This additional risk is, of course, attributable to the fact that the payment of interest
5 and principal to creditors has priority over the payment of dividends and return of capital to
6 equity investors. Hence, equity investors require a higher rate of return than the yield on long-
7 term corporate bonds.

8 The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs
9 the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk.
10 Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification
11 to systematic (or market) risk as measured by beta.

12 The Comparable Earnings approach measures the returns expected/experienced by other
13 non-regulated firms and has been used extensively in rate of return analysis for over a half
14 century. However, its popularity diminished in the 1970s and 1980s with the popularization of
15 market-based models. Recently, there has been renewed interest in this approach. Indeed, the
16 financial community has expressed the view that the regulatory process must consider the
17 returns which are being achieved in the non-regulated sector so that public utilities can compete
18 effectively in the capital markets. Indeed, with additional competition being introduced
19 throughout the traditionally regulated public utility industry, returns expected to be realized by
20 non-regulated firms have become increasing relevant in the ratesetting process. The
21 Comparable Earnings approach considers directly those requirements and it fits the established
22 standards for a fair rate of return set forth in the Bluefield and Hope decisions. The Hope

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- 1 decision requires that a fair return for a utility must be equal to that earned by firms of
- 2 comparable risk.

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DISCOUNTED CASH FLOW ANALYSIS

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Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = $\$100 / (1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

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In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

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DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp . In this circumstance:

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$$P_0 = \frac{D_1}{(1 + Kp)} + \frac{D_2}{(1 + Kp)^2} + \frac{D_3}{(1 + Kp)^3} + \dots + \frac{D_n}{(1 + Kp)^n}$$

1 If $D_1 = D_2 = D_3 = \dots = D_n$ as is the case for preferred stock, and n approaches infinity, as is the
2 case for non-callable preferred stock without a sinking fund, then this equation reduces to:

3
$$P_0 = \frac{D_1}{Kp}$$

4 This equation can be used to solve for the annual rate of return on a preferred stock when the
5 current price and subsequent annual dividends are known. For example, with $D_1 = \$1.00$, and
6 $P_0 = \$10$, then $Kp = \$1.00 \div \10 , or 10%.

7 The dividend discount equation, first shown, is the generic DCF valuation model for all
8 equities, both preferred and common. While preferred stock generally pays a constant dividend,
9 permitting the simplification subsequently noted, common stock dividends are not constant.
10 Therefore, absent some other simplifying condition, it is necessary to rely upon the generic
11 form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \dots, D_n$ are systematically related to
12 one another by a constant growth rate (g), so that $D_0(1 + g) = D_1, D_1(1 + g) = D_2, D_2(1 + g)$
13 $= D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock)
14 is greater than g , then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \text{ or } P_0 = \frac{D_0(1 + g)}{Ks - g}$$

15 which is the periodic form of the "Gordon" model.¹ Proof of the DCF equation is found in all
16 modern basic finance textbooks. This DCF equation can be easily solved as:

¹ Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposted the DCF model in its present form nearly two decades earlier.

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$$K_s = \frac{D_0(1+g)}{P_0} + g$$

1 which is the periodic form of the Gordon Model commonly applied in estimating equity rates
2 of return in rate cases. When used for this purpose, K_s is the annual rate of return on common
3 equity demanded by investors to induce them to hold a firm's common stock. Therefore, the
4 variables D_0 , P_0 and g must be estimated in the context of the market for equities, so that the
5 rate of return, which a public utility is permitted the opportunity to earn, has meaning and
6 reflects the investor-required cost rate.

7 Application of the Gordon model with market derived variables is straightforward. For
8 example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0)
9 of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF
10 formula provides a 13.4% rate of return. The dividend yield component in this instance is
11 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual
12 rate of return required by investors. The capital gain component of the total return may be
13 calculated with two adjacent future year prices. For example, in the eleventh year of the
14 holding period, the price per share would be \$17.10 as compared with the price per share of
15 \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

16 Some DCF devotees believe that it is more appropriate to estimate the required return
17 on equity with a model which permits the use of multiple growth rates. This may be a plausible
18 approach to DCF, where investors expect different dividend growth rates in the near term and
19 long run. If two growth rates, one near term and one long-run, are to be used in the context of a
20 price (P_0) of \$10.00, a dividend (D_0) of \$0.80, a near-term growth rate of 5.5%, and a long-run

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1 expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved
2 with a computer by iteration.

3 Use of DCF in Ratesetting

4 The DCF method can provide a misleading measure of the cost of equity in the
5 ratesetting process when stock prices diverge from book values by a meaningful margin. When
6 the difference between share values and book values is significant, the results from the DCF
7 can result in a misspecified cost of equity when those results are applied to book value. This is
8 because investor expected returns, as described by the DCF model, are related to the market
9 value of common stock. This discrepancy is shown by the following example. If it is assumed,
10 hypothetically, that investors require a 12.5% return on their common stock investment value
11 (i.e., the market price per share) when share values represent 150% of book value, investors
12 would require a total annual return of \$1.50 per share on a \$12.00 market value to realize their
13 expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost
14 rate base which is equivalent to the book value of common stock of \$8.00 per share, the utility's
15 actual earnings per share would be only \$1.00. This would result in a \$.50 per share earnings
16 shortfall which would deny the utility the ability to satisfy investor expectations.

17 As a consequence, a utility could not withstand these DCF results applied in a rate case
18 and also sustain its financial integrity. This is because \$1.00 of earnings per share and a 75%
19 dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $\$1.00 \times .75$
20 $= \$0.75$, and $\$1.00 - \$0.75 = \$0.25$, $\$8.00 = 3.125\%$). In this example, the earnings retention
21 growth rate plus the 6.25% dividend yield ($\$0.75 / \12.00) would equal 9.375% (6.25% +
22 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of
23 dividend payments on its book value (i.e., $\$0.75 / \$8.00 = 9.375\%$). This situation provides the

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1 utility with no earnings cushion for its dividend payment because the DCF result equals the
2 dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price
3 employed in my example were higher than 150% of book value, a "negative" earnings cushion
4 would develop and cause the need for a dividend reduction because the DCF result would be
5 less than the dividend rate on book value. For these reasons, the usefulness of the DCF method
6 significantly diminishes as market prices and book values diverge.

7 Further, there is no reason to expect that investors would necessarily value utility stocks
8 equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover,
9 high market-to-book ratios may be reflective of general market sentiment. Were regulators to
10 use the results of a DCF model, that fails to produce the required return when applied to an
11 original cost rate base, they would penalize a company with high market-to-book ratios. This
12 clearly would penalize a regulated firm and its investors that purchased the stock at its current
13 price. When investor expectations are not fulfilled, the market price per share will decline and
14 a new, different equity cost rate would be indicated from the lower price per share. This
15 condition suggests that the current price would be subject to disequilibrium and would not
16 allow a reasonable calculation of the cost of equity. This situation would also create a serious
17 disincentive for management initiative and efficiency. Within that framework, a perverse set of
18 goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the
19 reward for poor financial performance, while low rates of return would be the reward for good
20 financial performance. As such, the DCF results should not be used alone to determine the cost
21 of equity, but should be used along with other complementary methods.

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Dividend Yield

The historical annual dividend yields for the Electric Group and the Gas Group are shown on Schedules 3 and 4. The 1998-2002 five-year average dividend yields were 4.8% for the Electric Group and 4.7% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 6. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

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1 The procedure to adjust the average dividend yield for the expectation of a dividend
2 increase during the initial investment period will be at a rate of one-half the growth component,
3 developed below. The DCF equation, showing the quarterly dividend payments as D_0 , may be
4 stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

5 The adjustment factor, based upon one-half the expected growth rate developed in my direct
6 testimony, will be 2.750% (5.50% x .5) for the Electric Group and 3.125% (6.25% x .5) for the
7 Gas Group, which assumes that two dividend payments will be at the expected higher rate
8 during the initial investment period. Using the six-month average dividend yield as a base, the
9 prospective (forward) dividend yield would be 4.74% (4.61% x 1.02750) for the Electric Group
10 and 4.17% (4.04% x 1.03125) for the Gas Group.

11 Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as
12 follows:

$$K = \frac{D_0(1+g)^{25} + D_0(1+g)^{50} + D_0(1+g)^{75} + D_0(1+g)^{100}}{P_0} + g$$

13 This procedure confirms the reasonableness of the forward dividend yield previously
14 calculated. The quarterly discrete adjustment provides a dividend yield of 4.77% (4.61% x
15 1.03415) for the Electric Group and 4.20% (4.04% x 1.03877) for the Gas Group. The use of
16 an adjustment is required for the periodic form of the DCF in order to properly recognize that
17 dividends grow on a discrete basis.

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1 In either of the preceding DCF dividend yield adjustments, there is no recognition for
2 the compound returns attributed to the quarterly dividend payments. Investors have the
3 opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the
4 periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0} \right)^4 - 1 \right] + g$$

5 This DCF equation provides no further recognition of growth in the quarterly dividend.
6 Combining discrete quarterly dividend growth with quarterly compounding would provide the
7 following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0(1+g)^{25}}{P_0} \right)^4 - 1 \right] + g$$

8 A compounding of the quarterly dividend yield provides another procedure to recognize the
9 necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was
10 1.1525% ($4.61\% \div 4$) for the Electric Group and 1.0100% ($4.04\% \div 4$) for the Gas Group. The
11 compound dividend yield would be 4.75% ($1.011680^4 - 1$) for the Electric Group and 4.17%
12 ($1.010254^4 - 1$) for the Gas Group, recognizing quarterly dividend payments in a forward-
13 looking manner. These dividend yields conform with investors' expectations in the context of
14 reinvestment of their cash dividend.

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1 For the Electric Group, a 4.75% forward-looking dividend yield is the average (4.74%
2 + 4.77% + 4.75% = 14.26% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0 (1+.5g)$,
3 the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend
4 yield with discrete quarterly growth. The forward-looking dividend yield is 4.18% (4.17% +
5 4.20% + 4.17% = 12.54% ÷ 3) for the Gas Group, using each of the dividend yields discussed
6 previously.

7 Growth Rate

8 If viewed in its infinite form, the DCF model is represented by the discounted value of
9 an endless stream of growing dividends. It would, however, require 100 years of future
10 dividend payments so that the discounted value of those payments would equate to the present
11 price so that the discount rate and the rate of return shown by the simplified Gordon form of the
12 DCF model would be about the same. A century of dividend receipts represents an unrealistic
13 investment horizon from almost any perspective. Because stocks are not held by investors
14 forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most
15 relevant to investors' total return expectations. Hence, investor expected returns in the equity
16 market are provided by capital appreciation of the investment as well as receipt of dividends.
17 As such, the sale price of a stock can be viewed as a liquidating dividend which can be
18 discounted along with the annual dividend receipts during the investment holding period to
19 arrive at the investor expected return.

20 In its constant growth form, the DCF assumes that with a constant return on book
21 common equity and constant dividend payout ratio, a firm's earnings per share, dividends per
22 share and book value per share will grow at the same constant rate, absent any external
23 financing by a firm. Because these constant growth assumptions do not actually prevail in the

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1 capital markets, the capital appreciation potential of an equity investment is best measured by
2 the expected growth in earnings per share. Since the traditional form of the DCF assumes no
3 change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as
4 earnings per share. Hence, the capital gains yield is best measured by earnings per share
5 growth using company-specific variables.

6 Investors consider both historical and projected data in the context of the expected
7 growth rate for a firm. An investor can compute historical growth rates using compound
8 growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth
9 rates as provided in widely-circulated, influential publications. However, a traditional constant
10 growth DCF analysis that is limited to such inputs suffers from the assumption of no change in
11 the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as
12 earnings. Some of the factors which actually contribute to investors' expectations of earnings
13 growth and which should be considered in assessing those expectations, are: (i) the earnings
14 rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of
15 additional common equity, (iv) reacquisition of common stock previously issued, (v) changes
16 in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation
17 of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding
18 total return expectations, however, also reflect factors other than these inputs. Therefore, the
19 DCF model contains overly restrictive limitations when the growth component is stated in
20 terms of earnings per share (the basis for the capital gains yield) or dividends per share (the
21 basis for the infinite dividend discount model). In these situations, there is inadequate
22 recognition of the capital gains yields arising from stock price growth which could exceed
23 earnings or dividends growth.

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1 To assess the growth component of the DCF, analysts' projections of future growth
2 influence investor expectations as explained above. One influential publication is The Value
3 Line Investment Survey which contains estimated future projections of growth. The Value
4 Line Investment Survey provides growth estimates which are stated within a common
5 economic environment for the purpose of measuring relative growth potential. The basis for
6 these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line
7 hypothetical economic environment is represented by components and subcomponents of the
8 National Income Accounts which reflect in the aggregate assumptions concerning the
9 unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-
10 grade corporate bond interest rates, and Fed policies. Individual estimates begin with the
11 correlation of sales, earnings and dividends of a company to appropriate components or
12 subcomponents of the future National Income Accounts. These calculations provide a
13 consistent basis for the published forecasts. Value Line's evaluation of a specific company's
14 future prospects are considered in the context of specific operating characteristics that influence
15 the published projections. Of particular importance for regulated firms, Value Line considers
16 the regulatory quality, rates of return recently authorized, the historic ability of the firm to
17 actually experience the authorized rates of return, the firm's budgeted capital spending, the
18 firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and
19 frequent reference to Value Line in financial circles indicate that this publication has an
20 influence on investor judgment with regard to expectations for the future.

21 There are other sources of earnings growth forecasts. One of these sources is the
22 Institutional Brokers Estimate System ("IBES"), which has been published for many years.
23 The IBES service provided data on consensus earnings per share forecasts and five-year

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1 earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First
2 Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts.
3 The earnings estimates are obtained from financial analysts at brokerage research departments
4 and from institutions whose securities analysts are projecting earnings for companies in the
5 First Call universe of companies. Other services that tabulate earnings forecasts and publish
6 them are Zacks Investment Research and Market Guide (which is provided over the Internet by
7 Reuters). As with the First Call forecasts, Zacks and Reuters/Market Guide provide consensus
8 forecasts collected from analysts for most publically traded companies.

9 In each of these publications, forecasts of earnings per share for the current and
10 subsequent year receive prominent coverage. That is to say, Zacks, First Call/Thomson,
11 Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections
12 for the next year. While the DCF model typically focusses upon long-run estimates of growth,
13 stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the
14 near-term earnings per share growth rates should also be factored into a growth rate
15 determination.

16 Although forecasts of future performance are investor influencing², equity investors
17 may also rely upon the observations of past performance. Investors' expectations of future
18 growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent
19 that any serious investor would advise himself/herself of historical performance prior to taking
20 an investment position in a firm. Earnings per share and dividends per share represent the
21 principal financial variables which influence investor growth expectations.

² As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

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1 Other financial variables are sometimes considered in rate case proceedings. For
2 example, a company's internal growth rate, derived from the return rate on book common
3 equity and the related retention ratio, is sometimes considered. This growth rate measure is
4 represented by the Value Line forecast "BxR" shown on Schedule 11. Internal growth rates are
5 often used as a proxy for book value growth. Unfortunately, this measure of growth is often
6 not reflective of investor-expected growth. This is especially important when there is an
7 indication of a prospective change in dividend payout ratio, earned return on book common
8 equity, change in market-to-book ratios or other fundamental changes in the character of the
9 business. Nevertheless, I have also shown the historical and projected growth rates in book
10 value per share and internal growth rates.

11 Leverage Adjustment

12 As noted previously, the divergence of stock prices from book values creates a conflict
13 within the DCF model when the results of a market-derived cost of equity are applied to the
14 common equity account measured at book value in the ratesetting context. This is the situation
15 today where the market price of stock exceeds its book value for most companies. This
16 divergence of price and book value also creates a financial risk difference, whereby the
17 capitalization of a utility measured at its market value contains relatively less debt and more
18 equity than the capitalization measured at its book value. It is a well-accepted fact of financial
19 theory that a relatively higher proportion of equity in the capitalization has less financial risk
20 than another capital structure more heavily weighted with debt. This is the situation for the
21 Electric and Gas Groups where the market value of their capitalization contains more equity
22 than is shown by the book capitalization. The following comparison demonstrates this situation
23 where the market capitalization is developed by taking the "Fair Value of Financial

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1 Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial
 2 Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and
 3 the market value of the common equity using the price of stock. The comparison of capital
 4 structure ratios is:

	<u>Electric Group</u>		<u>Gas Group</u>	
	<u>Market</u>	<u>Book</u>	<u>Market</u>	<u>Book</u>
	<u>Value</u>	<u>Value</u>	<u>Value</u>	<u>Value</u>
9 Long-term Debt	46.81%	52.19%	38.85%	50.08%
10 Preferred Stock	3.39	4.42	2.21	2.89
11 Common Equity	<u>49.79</u>	<u>43.38</u>	<u>58.94</u>	<u>47.04</u>
13 Total	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>

15 With regard to the capital structure ratios represented by the carrying amounts shown above,
 16 there are some variances from the ratios shown on Schedules 3 and 4. These variances arise
 17 from the use of balance sheet values in computing the capital structure ratios shown on
 18 Schedules 3 and 4, and the use of the Carrying Amounts of the Financial Instruments according
 19 to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the
 20 Fair Value amounts used in the comparison calculations).

21 With the capital ratios calculated above, is necessary to first calculate the cost of equity
 22 for a firm without any leverage. The cost of equity for an unleveraged firm using the capital
 23 structure ratios calculated with market values is:

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1
$$k_u = k_e - (((k_u - i) (1-t) D / E) - (k_u - d) P / E)$$

2 Electric Group

3
$$8.71\% = 10.25\% - (((8.71\% - 6.43\%) .65) 46.81\% / 49.79\%) - (8.71\% - 6.76\%) 3.39\% / 49.79\%$$

4 Gas Group

5
$$9.17\% = 10.43\% - (((9.17\% - 6.43\%) .65) 38.85\% / 58.94\%) - (9.17\% - 6.76\%) 2.21\% / 58.94\%$$

6 where k_u = cost of equity for an all-equity firm, k_e = market determined cost equity, i = cost of
 7 debt³, d = dividend rate on preferred stock⁴, D = debt ratio, P = preferred stock ratio, and E =
 8 common equity ratio. Using the market value of each group's capitalization, the formula
 9 shown above indicates that the cost of equity for a firm with 100% equity is 8.71% for the
 10 Electric Group and 9.17% for the Gas Group. Having determined that the cost of equity for a
 11 firm with 100% equity, the rate of return on common equity associated with the book value
 12 capital structure is:

13
$$k_e = k_u + (((k_u - i) (1-t) D / E) + (k_u - d) P / E)$$

14 Electric Group

15
$$10.69\% = 8.71\% + (((8.71\% - 6.43\%) .65) 52.19\% / 43.38\%) + (8.71\% - 6.76\%) 4.42\% / 43.38\%$$

16 Gas Group

17
$$11.22\% = 9.17\% + (((9.17\% - 6.43\%) .65) 50.08\% / 47.04\%) + (9.17\% - 6.76\%) 2.89\% / 47.04\%$$

³ The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

⁴ The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

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INTEREST RATES

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Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and

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1 hence reflect only the real rate of interest, compensation for expected inflation, and maturity
2 risk. The Treasury has been issuing inflation-indexed notes which automatically provide
3 compensation to investors for future inflation, thereby providing a lower current yield on these
4 issues.

Interest Rate Environment

5
6 Federal Reserve Board ("Fed") policy actions which impact directly short-term interest
7 rates also substantially affect investor sentiment in long-term fixed-income securities markets.
8 In this regard, the Fed has often pursued policies designed to build investor confidence in the
9 fixed-income securities market. Formative Fed policy has had a long history, as exemplified by
10 the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the
11 financial system which increased the level and volatility of interest rates. The Fed has
12 indicated that it will follow a monetary policy designed to promote noninflationary economic
13 growth.

14 As background to the recent levels of interest rates, history shows that the Open Market
15 Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower
16 short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy
17 was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing
18 economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit
19 crunch. Thereafter, the Federal government initiated several bold proposals to deal with future
20 borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury
21 borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term
22 interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

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1 On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e.,
2 the interest rate on excess overnight bank reserves). The initial increase represented the first
3 rise in short-term interest rates in five years. The series of seven increases doubled the Fed
4 Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to
5 move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in
6 long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury
7 bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

8 Beginning in mid-February 1996, long-term interest rates moved upward from their
9 previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest
10 rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period
11 leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within
12 this range. After the election, interest rates moderated, returning to a level somewhat below the
13 previous trading range. Thereafter, in December 1996, interest rates returned to a range of
14 6.5% to 7.0% which existed for much of 1996.

15 On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-
16 quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed
17 Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent
18 strength of demand in the economy, which it feared would increase the risk of inflationary
19 imbalances that could eventually interfere with the long economic expansion.

20 In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in
21 response to an increase in demand for Treasury securities caused by a flight to safety triggered
22 by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market
23 makes these bonds an attractive investment in times of crisis. This is because Treasury

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1 securities encompass a very large market which provides ease of trading and carry a premium
2 for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically
3 important 6% level for the first time since 1993.

4 Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within
5 a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of
6 1998, there was further deterioration of investor confidence in global financial markets. This
7 loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and
8 fears associated with problems in Latin America. While not significant to the global economy
9 in the aggregate, the August 17 default by Russia had a significant negative impact on investor
10 confidence, following earlier discontent surrounding the crisis in Asia. These events
11 subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance
12 to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds
13 of riskier companies. These events contributed to the failure of the hedge fund, Long-Term
14 Capital Management.

15 In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term
16 Congressional elections. The FOMC's action was based upon concerns over how increasing
17 weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the
18 FOMC had been more concerned about fighting inflation than the state of the economy. The
19 initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-
20 term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury
21 yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely
22 anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third

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1 reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the
2 Fed Funds rate to 4.75%.

3 All of these events prompted an increase in the prices for Treasury bonds which lead to
4 the low yields described above. Another factor that contributed to the decline in yields on
5 long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to
6 market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of
7 Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and
8 lower yields. In addition, rumors of some struggling hedge funds unwinding their positions
9 further added to the gains in Treasury bond prices.

10 The financial crisis that spread from Asia to Russia and to Latin America pushed
11 nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just
12 when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to
13 take advantage of appreciation in the Treasury market. This resulted in a certain amount of
14 exuberance for Treasury bond investments that formerly was reserved for the stock market.
15 Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury
16 yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter
17 returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields
18 in a two-week time frame is remarkable.

19 Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its
20 actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February
21 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%.
22 This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher
23 than the level that occurred at the height of the Asian currency and stock market crisis. At the

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1 time, these actions were taken in response to more normally functioning financial markets, tight
2 labor markets, and a reversal of the monetary ease that was required earlier in response to the
3 global financial market turmoil.

4 As the year 2000 drew to a close, economic activity slowed and consumer confidence
5 began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC
6 reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate
7 to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary
8 policy" to eroding consumer and business confidence exemplified by weaker retail sales and
9 business spending on capital equipment and cut backs in manufacturing production.
10 Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August
11 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points
12 decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate
13 to 3.50%. The FOMC observed on August 21, 2001:

14 "Household demand has been sustained, but business profits and
15 capital spending continue to weaken and growth abroad is
16 slowing, weighing on the U.S. economy. The associated easing
17 of pressures on labor and product markets is expected to keep
18 inflation contained.

19
20 Although long-term prospects for productivity growth and the
21 economy remain favorable, the Committee continues to believe
22 that against the background of its long-run goals of price
23 stability and sustainable economic growth and of the
24 information currently available, the risks are weighted mainly
25 toward conditions that may generate economic weakness in the
26 foreseeable future."

27
28 After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis
29 points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001

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1 and followed the four-day closure of the financial markets following the terrorist attacks. The
2 second reduction occurred at the October 2 meeting of the FOMC where it observed:

3 “The terrorist attacks have significantly heightened uncertainty
4 in an economy that was already weak. Business and household
5 spending as a consequence are being further damped.
6 Nonetheless, the long-term prospects for productivity growth
7 and the economy remain favorable and should become evident
8 once the unusual forces restraining demand abate.”
9

10 Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and
11 by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by
12 the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by
13 4.75% and resulted in 1.75% for the Fed Funds rate.

14 *In an attempt to deal with weakening fundamentals in the economy recovering from the*
15 recession that began in March 2001, the FOMC provided a psychologically important one-half
16 percentage point reduction in the federal funds rate. The rate cut was twice as large as the
17 market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC
18 stated that:

19 “The Committee continues to believe that an accommodative
20 stance of monetary policy, coupled with still-robust underlying
21 growth in productivity, is providing important ongoing support
22 to economic activity. However, incoming economic data have
23 tended to confirm that greater uncertainty, in part attributable to
24 heightened geopolitical risks, is currently inhibiting spending,
25 production, and employment. Inflation and inflation
26 expectations remain well contained.
27

28 In these circumstances, the Committee believes that today’s
29 additional monetary easing should prove helpful as the economy
30 works its way through this current soft spot. With this action,
31 *the Committee believes that, against the background of its long-*
32 run goals of price stability and sustainable economic growth and
33 of the information currently available, the risks are balanced
34 with respect to the prospects for both goals in the foreseeable
35 future.”

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1 As 2003 unfolded, there was a continuing expectation of lower yields on Treasury
2 securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of
3 the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a
4 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25
5 basis points on June 25, 2003. In announcing its action, the FOMC stated:

6 "The Committee continues to believe that an accommodative
7 stance of monetary policy, coupled with still robust underlying
8 growth in productivity, is providing important ongoing support
9 to economic activity. Recent signs point to a firming in
10 spending, markedly improved financial conditions, and labor
11 and product markets that are stabilizing. The economy,
12 nonetheless, has yet to exhibit sustainable growth. With
13 inflationary expectations subdued, the Committee judged that a
14 slightly more expansive monetary policy would add further
15 support for an economy which it expects to improve over
16 time."

17
18 Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher
19 yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's
20 disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the
21 Fed will not use unconventional methods for implementing monetary policy, (iii) growing
22 confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be
23 \$455 billion in 2003 (reported subsequently, the actual deficit was \$374 billion) and \$475
24 billion in 2004 (revised subsequently, the estimated deficit is \$500 billion in 2004). All these
25 factors significantly changed the sentiment in the bond market.

26 For the remainder of 2003, the FOMC continued with its balanced monetary policy,
27 thereby retaining the 1% Fed Funds rate. However, in 2004, it appears that its policy may be in
28 transition, when on January 28, 2004 the FOMC stated:

29 "The Committee continues to believe that an accommodative stance of
30 monetary policy, coupled with robust underlying growth in productivity,

APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

1 is providing important ongoing support to economic activity. The
2 evidence accumulated over the intermeeting period confirms that output
3 is expanding briskly. Although new hiring remains subdued, other
4 indicators suggest an improvement in the labor market. Increases in
5 core consumer prices are muted and expected to remain low.
6

7 The Committee perceives that the upside and downside risks to the
8 attainment of sustainable growth for the next few quarters are roughly
9 equal. The probability of an unwelcome fall in inflation has diminished
10 in recent months and now appears almost equal to that of a rise in
11 inflation. With inflation quite low and resource use slack, the Committed
12 believes that it can be patient in removing its policy accommodation.”
13

14 Public Utility Bond Yields

15 The Risk Premium analysis of the cost of equity is represented by the combination of a
16 firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the
17 additional risk associated with the equity of a firm as explained in Appendix G. Due to the
18 senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the
19 prior claim which lenders have on the earnings and assets of a corporation.

20 As a generalization, all interest rates track to varying degrees of the benchmark yields
21 established by the market for Treasury securities. Public utility bond yields usually reflect the
22 underlying Treasury yield associated with a given maturity plus a spread to reflect the specific
23 credit quality of the issuing public utility. Market sentiment can also have an influence on the
24 spreads as described below. The spread in the yields on public utility bonds and Treasury
25 bonds varies with market conditions, as does the relative level of interest rates at varying
26 maturities shown by the yield curve.

27 Pages 1 and 2 of Schedule 12 provide the recent history of long-term (i.e., maturities as
28 close as possible to 30 years) public utility bond yields for each of the "investment grades" (i.e.,
29 Aaa, Aa, A and Baa). The top four rating categories shown on Schedule 12 are generally

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1 regarded as eligible for bank investments under commercial banking regulations. These
2 investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

3 A relatively long history of the spread between the yields on long-term A rated public
4 utility bonds and long-term Treasury bonds are shown on page 3 of Schedule 12. There, it is
5 shown that the spread in these yields declined after the 1987 stock market crash. Those spreads
6 stabilized at about the one percentage point level for the years 1992 through 1997. With the
7 aversion to risk and flight to quality described earlier, a significant widening of the spread in
8 the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after
9 an initial widening of the spread that began in the fourth quarter of 1997. The significant
10 widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by
11 the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt
12 on August 17, some investors had to cover short positions when Treasury prices spiked upward.
13 Short covering by investors that guessed wrong on the relationship between corporate and
14 Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand
15 for them. This helped to contribute to a widening of the spreads between corporate and
16 Treasury bonds.

17 As indicated by the dynamics described earlier, there has been a disconnection from the
18 previous relationship between the yields on corporate debt and Treasury bonds. As shown on
19 page 3 of Schedule 12, the spread in yields between A rated public utility bonds and long-term
20 Treasury bonds widened from about one percentage point prior to 1998 to 1.46% in 1998,
21 1.75% in 1999, 2.30% in 2000, 2.27% in 2001, 1.95% in 2002 and 1.56% in 2003. In essence,
22 the cost of corporate debt and equity has disconnected from the yields on long-term Treasury
23 bonds due to a general aversion to risk and the shrinking supply of long-term Treasury bonds.

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1 As shown by the monthly data presented on pages 4 and 5 of Schedule 12, the interest rate
2 spread between the yields on long-term Treasury bonds and A rated public utility bonds was
3 1.49 percentage points for the twelve-months ended January 2004. For the six- and three-
4 month periods ending January 2004, the yield spread was 1.21% and 1.13%, respectively. This
5 situation continues to point to the high cost of corporate capital vis-à-vis the yield on Treasury
6 obligations.

Risk-Free Rate of Return in the CAPM

7
8 Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 14
9 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of
10 the CAPM would advocate the use of short-term treasury yields (and some would argue for the
11 yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of
12 longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has
13 indicated:

14 The Cost of Capital in a Regulatory Environment. When discounting
15 cash flows projected over a long period, it is necessary to discount
16 them by a long-term cost of capital. Additionally, regulatory
17 processes for setting rates often specify or suggest that the desired rate
18 of return for a regulated firm is that which would allow the firm to
19 attract and retain debt and equity capital over the long term. Thus, the
20 long-term cost of capital is typically the appropriate cost of capital to
21 use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992
22 Yearbook, pages 118-119)
23

24 As indicated above, long-term Treasury bond yields represent the correct measure of the risk-
25 free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be
26 avoided for several reasons. First, rates should be set on the basis of financial conditions that
27 will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields
28 are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy,

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- 1 political, and economic situations. Moreover, Treasury bill yields have been shown to be
- 2 empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-
- 3 free rate of return in the CAPM should be derived from quality long-term corporate bonds.

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RISK PREMIUM ANALYSIS

1
2 The cost of equity requires recognition of the risk premium required by common
3 equities over long-term corporate bond yields. In the case of senior capital, a company
4 contracts for the use of long-term debt capital at a stated coupon rate for a specific period of
5 time and in the case of preferred stock capital at a stated dividend rate, usually with provision
6 for redemption through sinking fund requirements. In the case of senior capital, the cost rate is
7 *known with a high degree of certainty because the payment for use of this capital is a*
8 contractual obligation, and the future schedule of payments is known. In essence, the investor-
9 expected cost of senior capital is equal to the realized return over the entire term of the issue,
10 absent default.

11 The cost of equity, on the other hand, is not fixed, but rather varies with investor
12 perception of the risk associated with the common stock. Because no precise measurement
13 exists as to the cost of equity, informed judgment must be exercised through a study of various
14 market factors which motivate investors to purchase common stock. In the case of common
15 equity, the realized return rate may vary significantly from the expected cost rate due to the
16 uncertainty associated with earnings on common equity. This uncertainty highlights the added
17 risk of a common equity investment.

18 As one would expect from traditional risk and return relationships, the cost of equity is
19 affected by expected interest rates. As noted in Appendix F, yields on long-term corporate
20 bonds traditionally consist of a real rate of return without regard to inflation, an increment to
21 reflect investor perception of expected future inflation, the investment horizon shown by the
22 term of the issue until maturity, and the credit risk associated with each rating category.

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1 corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern
2 to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or
3 starting point with which to track and measure the cost rate of common equity capital. There is
4 no need to segment the bond yield according to its components, because it is the total return
5 demanded by investors that is important for determining the risk rate differential for common
6 equity. This is because the complete bond yield provides the basis to determine the differential,
7 and as such, consistency requires that the computed differential must be applied to the complete
8 bond yield when applying the risk premium approach. To apply the risk rate differential to a
9 partial bond yield would result in a misspecification of the cost of equity because the computed
10 differential was initially determined by reference to the entire bond return.

11 The risk rate differential between the cost of equity and the yield on long-term corporate
12 bonds can be determined by reference to a comparison of holding period returns (here defined
13 as one year) computed over long time spans. This analysis assumes that over long periods of
14 time investors' expectations are on average consistent with rates of return actually achieved.
15 Accordingly, historical holding period returns must not be analyzed over an unduly short period
16 because near-term realized results may not have fulfilled investors' expectations. Moreover,
17 specific past period results may not be representative of investment fundamentals expected for
18 the future. This is especially apparent when the holding period returns include negative returns
19 which are not representative of either investor requirements of the past or investor expectations
20 for the future. The short-run phenomenon of unexpected returns (either positive or negative)
21 demonstrates that an unduly short historical period would not adequately support a risk
22 premium analysis. It is important to distinguish between investors' motivation to invest, which

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1 encompass positive return expectations, and the knowledge that losses can occur. No rational
2 investor would forego payment for the use of capital, or expect loss of principal, as a basis for
3 investing. Investors will hold cash rather than invest with the expectation of a loss.

4 Within these constraints, page 1 of Schedule 13 provides the historical holding period
5 returns for the S&P Public Utility Index which has been independently computed and the
6 historical holding period returns for the S&P Composite Index which have been reported in
7 Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins
8 with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public
9 Utility Index. I have considered all reliable data for this study to avoid the introduction of a
10 particular bias to the results. The measurement of the common equity return rate differential is
11 based upon actual capital market performance using realized results. As a consequence, the
12 underlying data for this risk premium approach can be analyzed with a high degree of
13 precision. Informed professional judgment is required only to interpret the results of this study,
14 but not to quantify the component variables.

15 The risk rate differentials for all equities, as measured by the S&P Composite, are
16 established by reference to long-term corporate bonds. For public utilities, the risk rate
17 differentials are computed with the S&P Public Utilities as compared with public utility bonds.

18 The measurement procedure used to identify the risk rate differentials consisted of
19 arithmetic means, geometric means, and medians for each series. Measures of central tendency
20 of the results from the historical periods provide the best indication of representative rates of
21 return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic
22 mean because a utility must expect to earn its cost of capital in each year in order to provide

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

1 investors with their long-term expectations. In other contexts, such as pension determinations,
2 compound rates of return, as shown by the geometric means, may be appropriate. The median
3 returns are also appropriate in ratesetting because they are a measure of the central tendency of
4 a single period rate of return. Median values have also been considered in this analysis because
5 they provide a return which divides the entire series of annual returns in half and are
6 representative of a return that symbolizes, in a meaningful way, the central tendency of all
7 annual returns contained within the analysis period. Medians are regularly included in many
8 investor-influencing publications.

9 As previously noted, the arithmetic mean provides the appropriate point estimate of the
10 risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases
11 requires the use of the arithmetic means. To supplement my analysis, I have also used the rates
12 of return taken from the geometric mean and median for each series to provide the bounds of
13 the range to measure the risk rate differentials. This further analysis shows that when selecting
14 the midpoint from a range established with the geometric means and medians, the arithmetic
15 mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928
16 through 2003, the risk premiums for each class of equity are:

	<u>S&P Composite</u>	<u>S&P Public Utilities</u>	
17			
18			
19			
20	Arithmetic Mean	<u>5.91%</u>	<u>4.98%</u>
21			
22	Geometric Mean	4.24%	2.85%
23	Median	<u>11.29%</u>	<u>6.71%</u>
24			
25	Midpoint of Range	<u>7.77%</u>	<u>4.78%</u>
26			
27	Average	<u>6.84%</u>	<u>4.88%</u>
28			

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1 The empirical evidence suggests that the common equity risk premium is higher for the S&P
2 Composite Index compared to the S&P Public Utilities.

3 If, however, specific historical periods were also analyzed in order to match more
4 closely historical fundamentals with current expectations, the results provided on page 2 of
5 Schedule 13 should also be considered. One of these sub-periods included the 52-year period,
6 1952-2003. These years follow the historic 1951 Treasury-Federal Reserve Accord which
7 affected monetary policy and the market for government securities.

8 A further investigation was undertaken to determine whether realignment has taken
9 place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the
10 financial markets. In each case, the public utility risk premiums were computed by using the
11 arithmetic mean, and the geometric means and medians to establish the range shown by those
12 values. The time periods covering the more recent periods 1974 through 2003 and 1979
13 through 2003 contain events subsequent to the initial oil shock and the advent of monetarism as
14 Fed policy, respectively. For the 52-year, 30-year and 25-year periods, the public utility risk
15 premiums were 5.52%, 4.49%, and 4.47% respectively, as shown by the average of the specific
16 point-estimates and the midpoint of the ranges provided on page 2 of Schedule 13.

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CAPITAL ASSET PRICING MODEL

1
2 Modern portfolio theory provides a theoretical explanation of expected returns on
3 portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the
4 way prices of individual securities are determined in efficient markets where information is
5 freely available and is reflected instantaneously in security prices. The CAPM states that the
6 expected rate of return on a security is determined by a risk-free rate of return plus a risk
7 premium which is proportional to the non-diversifiable (or systematic) risk of a security.

8 The CAPM theory has several unique assumptions that are not common to most other
9 methods used to measure the cost of equity. As with other market-based approaches, the
10 CAPM is an expectational concept. There has been significant academic research conducted
11 that found that the empirical market line, based upon historical data, has a less steep slope and
12 higher intercept than the theoretical market line of the CAPM. For equities with a beta less
13 than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate
14 the realistic expectation of investors in comparison with the empirical market line which shows
15 that the CAPM may potentially misspecify investors' required return.

16 The CAPM considers changing market fundamentals in a portfolio context. The
17 balance of the investment risk, or that characterized as unsystematic, must be diversified.
18 Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this
19 contention is not completely justified because the business and financial risk of an individual
20 company, including regulatory risk, are widely discussed within the investment community and
21 therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that
22 through portfolio diversification, investors will minimize the effect of the unsystematic

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 (diversifiable) component of investment risk. Because it is not known whether the average
2 investor holds a well-diversified portfolio, the CAPM must also be used with other models of
3 the cost of equity.

4 To apply the traditional CAPM theory, three inputs are required: the beta coefficient
5 (" β "), a risk-free rate of return (" R_f "), and a market premium (" $R_m - R_f$ "). The cost of equity
6 stated in terms of the CAPM is:

$$7 \quad k = R_f + \beta (R_m - R_f)$$

8 As previously indicated, it is important to recognize that the academic research has
9 shown that the security market line was flatter than that predicted by the CAPM theory and it
10 had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas
11 less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for
12 portfolios with betas above 1.0, these companies had lower returns than indicated by the
13 traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification
14 investors will minimize the effect of the unsystematic (diversifiable) component of investment
15 risk. Therefore, the CAPM must also be used with other models of the cost of equity,
16 especially when it is not known whether the average public utility investor holds a well-
17 diversified portfolio.

18 Beta

19 The beta coefficient is a statistical measure which attempts to identify the non-
20 diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of
21 return on a particular security with general market movements. Under the CAPM theory, a
22 security that has a beta of 1.0 should theoretically provide a rate of return equal to the return

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 rate provided by the market. When employing stock price changes in the derivation of beta, a
2 stock with a beta of 1.0 should exhibit a movement in price which would track the movements
3 in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one
4 percent increase in the return on the market will result, on average, in a one percent increase in
5 the return on the particular investment. An investment which has a beta less than 1.0 is
6 considered to be less risky than the market.

7 The beta coefficient (" β "), the one input in the CAPM application which specifically
8 applies to an individual firm, is derived from a statistical application which regresses the
9 returns on an individual security (dependent variable) with the returns on the market as a whole
10 (independent variable). The beta coefficients for utility companies typically describe a small
11 proportion of the total investment risk because the coefficients of determination (R^2) are low.

12 Page 1 of Schedule 14 provides the betas published by Value Line. By way of
13 explanation, the Value Line beta coefficient is derived from a "straight regression" based upon
14 the percentage change in the weekly price of common stock and the percentage change weekly
15 of the New York Stock Exchange Composite average using a five-year period. The raw
16 historical beta is adjusted by Value Line for the measurement effect resulting in overestimates
17 in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to
18 the nearest .05 increment. Value Line does not consider dividends in the computation of its
19 betas.

Market Premium

21 The final element necessary to apply the CAPM is the market premium. The market
22 premium by definition is the rate of return on the total market less the risk-free rate of return

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 ("Rm - Rf"). In this regard, the market premium in the CAPM has been calculated from the total
 2 return on the market of equities using forecast and historical data. The future market return is
 3 established with forecasts by Value Line using estimated dividend yields and capital
 4 appreciation potential.

5 With regard to the forecast data, I have relied upon the Value Line forecasts of capital
 6 appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to
 7 the February 13, 2004, edition of The Value Line Investment Survey Summary and Index, (see
 8 page 5 of Schedule 14) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of February 13, 2004	1.7%	+	8.78% ¹	=	10.48%

15 The tabulation shown above provides the dividend yield and capital gains yield of the
 16 companies followed by Value Line. With the 10.48% forecast market return and the 5.75%
 17 risk-free rate of return, a 4.73% (10.48% - 5.75%) market premium would be indicated using
 18 forecast market data.

19 With regard to the historical data, I provided the rates of return from long-term
 20 historical time periods that have been widely circulated among the investment and academic
 21 community over the past several years, as shown on page 6 of Schedule 12. These data are
 22 published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the
 23 data provided on page 6 of Schedule 14, I calculate a market premium using the common stock
 24 arithmetic mean returns of 12.4% less government bond arithmetic mean returns of 5.8%. For

¹ The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., 1.40²⁵ - 1).

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 the period 1926-2002, the market premium was 6.6% (12.4% - 5.8%).

2 I should note that the arithmetic mean must be used in the CAPM because it is a single
3 period model. It is further confirmed by Ibbotson who has indicated:

4 *Arithmetic Versus Geometric Differences*

5 For use as the expected equity risk premium in the CAPM, the
6 *arithmetic* or *simple difference* of the *arithmetic* means of stock
7 market returns and riskless rates is the relevant number. This is
8 because the CAPM is an additive model where the cost of capital is
9 the sum of its parts. Therefore, the CAPM expected equity risk
10 premium must be derived by arithmetic, *not geometric*, subtraction.

11 *Arithmetic Versus Geometric Means*

12 The expected equity risk premium should always be calculated using
13 the arithmetic mean. The arithmetic mean is the rate of return which,
14 when compounded over multiple periods, gives the mean of the
15 probability distribution of ending wealth values. This makes the
16 arithmetic mean return appropriate for computing the cost of capital.
17 The discount rate that equates expected (mean) future values with the
18 present value of an investment is that investment's cost of capital.
19 The logic of using the discount rate as the cost of capital is reinforced
20 by noting that investors will discount their (mean) ending wealth
21 values from an investment back to the present using the arithmetic
22 mean, for the reason given above. They will therefore require such an
23 expected (mean) return prospectively (that is, in the present looking
24 toward the future) to commit their capital to the investment. (Stocks,
25 Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

26
27
28 For the CAPM, a market premium of 5.67% ($6.6\% + 4.73\% = 11.33\% \div 2$) would be
29 reasonable which is the average of the 6.6% using historical data and a market premium of
30 4.73% using forecasts.

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COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

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Financial Strength

1
2
3 The financial strength of each of the more than 1,600 companies
4 in the VS II data base is rated relative to all the others. The
5 ratings range from A++ to C in nine steps. (For screening
6 purposes, think of an A rating as "greater than" a B). Companies
7 that have the best relative financial strength are given an A++
8 rating, indicating an ability to weather hard times better than the
9 vast majority of other companies. Those who don't quite merit
10 the top rating are given an A+ grade, and so on. A rating as low
11 as C++ is considered satisfactory. A rating of C+ is well below
12 average, and C is reserved for companies with very serious
13 financial problems. The ratings are based upon a computer
14 analysis of a number of key variables that determine (a) financial
15 leverage, (b) business risk, and (c) company size, plus the
16 judgment of Value Line's analysts and senior editors regarding
17 factors that cannot be quantified across-the-board for companies.
18 The primary variables that are indexed and studied include equity
19 coverage of debt, equity coverage of intangibles, "quick ratio",
20 accounting methods, variability of return, fixed charge coverage,
21 stock price stability, and company size.

Price Stability Index

22
23
24
25 An index based upon a ranking of the weekly percent changes in
26 the price of the stock over the last five years. The lower the
27 standard deviation of the changes, the more stable the stock.
28 Stocks ranking in the top 5% (lowest standard deviations) carry a
29 Price Stability Index of 100; the next 5%, 95; and so on down to
30 5. One standard deviation is the range around the average weekly
31 percent change in the price that encompasses about two thirds of
32 all the weekly percent change figures over the last five years.
33 When the range is wide, the standard deviation is high and the
34 stock's Price Stability Index is low.

Beta

35
36
37
38 A measure of the sensitivity of the stock's price to overall
39 fluctuations in the New York Stock Exchange Composite
40 Average. A Beta of 1.50 indicates that a stock tends to rise (or
41 fall) 50% more than the New York Stock Exchange Composite
42 Average. Use Beta to measure the stock market risk inherent in
43 any diversified portfolio of, say, 15 or more companies.
44 Otherwise, use the Safety Rank, which measures total risk
45 inherent in an equity, including that portion attributable to market
46 fluctuations. Beta is derived from a least squares regression

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1 analysis between weekly percent changes in the price of a stock
2 and weekly percent changes in the NYSE Average over a period
3 of five years. In the case of shorter price histories, a smaller time
4 period is used, but two years is the minimum. The Betas are
5 periodically adjusted for their long-term tendency to regress
6 toward 1.00.
7

8 Technical Rank
9

10 A prediction of relative price movement, primarily over the next
11 three to six months. It is a function of price action relative to all
12 stocks followed by Value Line. Stocks ranked 1 (Highest) or 2
13 (Above Average) are likely to outpace the market. Those ranked
14 4 (Below Average) or 5 (Lowest) are not expected to outperform
15 most stocks over the next six months. Stocks ranked 3 (Average)
16 will probably advance or decline with the market. Investors
17 should use the Technical and Timeliness Ranks as complements
18 to one another.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 10

Direct Testimony of Julie M. Cannell

1

2 Q. Please summarize your experience that allows you to provide testimony
3 about the viewpoint of investors.

4 A. As a securities analyst, I specialized in the electric utility industry and the
5 individual companies comprising it. As a portfolio manager, I applied that
6 knowledge, along with investment fundamentals, toward investment deci-
7 sions on behalf of institutions and individual investors. And, as an advisor
8 to the industry, a great deal of my work has dealt with investors and their
9 perceptions.

10

11 Q. As an analyst or portfolio manager, did you follow PPL Corporation?

12 A. Yes, I did. Both Lord Abbett and America's Utility Fund periodically main-
13 tained a holding in the common stock of PPL Corporation ("PPL"), which
14 was then named Pennsylvania Power & Light Company.

15

16 Q. Please summarize the key points of your testimony.

17 A. The risk of investing in the electric utility industry has risen substantially in
18 recent years on an industry-wide basis. Any company-specific risks are
19 additive. Equity investors today are seeking companies that can offer
20 stability in terms of their outlook for earnings and dividends. Fixed income
21 investors look for stable and adequate cash flows to ensure payment of
22 principal and interest when due. Essential to providing that stability is a
23 regulatory environment that is constructive; in other words, one that

1 provides return levels sufficient to compensate the investor for the risk
2 assumed in making an investment. Because the ability to pay dividends is
3 directly related to a company's earnings power, an investor demands an
4 allowed return sufficient to provide earnings that will allow an appropriate
5 dividend.

6 Credit issues have also become critically important not only to fixed
7 income investors, but also to equity investors. While credit downgrades
8 *initially impacted only the most troubled companies*, rating agencies are
9 now scrutinizing all utilities more carefully and changing ratings more
10 frequently. When a regulatory climate is perceived not to provide a
11 supportive financial framework for a utility, the agencies can be expected
12 to downgrade the company's securities.

13 The Company's debt ratings were downgraded last year by
14 Standard & Poor's Corporation. Deteriorating credit quality increases the
15 cost of capital for a utility, which then further stresses its financial condi-
16 tion. Thus, as industry fundamentals continue to change and evolve, it is
17 increasingly important that stability be present in an investment, and that
18 any risk be assessed on a prospective basis. The issue of a strong finan-
19 cial profile is critically important to investors given both their experiences
20 in the market in recent years and uncertainties about electricity utility
21 fundamentals in the post-restructuring period. Investors and rating
22 agencies will be looking particularly closely at the results of rate cases
23 following expiration of rate caps.

1

2 Q. Please provide the Commission with a historical perspective of investing in
3 utilities.

4 A. Electric utilities historically have been regarded as defensive investment
5 vehicles. The industry's monopoly character insulated it somewhat from
6 the fluctuations of economic cycles. Even when the economy was
7 slowing, utilities typically earned a reasonable profit – unlike some
8 industrial companies, whose earnings levels could be quite negatively
9 impacted in the same environment. The reliability of earnings streams for
10 utilities also permitted most utilities to continue to pay dividends during
11 both good and bad economic cycles. Because they historically paid out a
12 large proportion of their earnings as dividends, and because their large
13 construction programs kept them dependent on the capital markets, utility
14 stocks were traditionally viewed as bond substitutes. This caused utility
15 stocks to move closely in line with the direction of interest rates, but in an
16 inverse relationship. That is, utility stock prices rose when interest rates
17 fell, and vice versa. These factors made utilities a preferred investment
18 during economic slowdowns or recessions.

19

20 Q. Have the recent changes in the industry increased the risk of investing in
21 electric utilities?

22 A. Yes. Just as the industry is in transition, so are investors evolving in how
23 they approach making investments in utilities. Put in the simplest terms,

1 investors understand that the predictability of the industry's earnings
2 stream has been undermined by electric industry restructuring together
3 with technological, economic and policy changes. There is uncertainty
4 regarding the pace at which customers will choose third party electric
5 suppliers; whether legislatures/regulators will continue electric utilities'
6 provider of last resort obligations and how electric utilities will recover the
7 cost of such obligations; whether legislatures/regulators will permit, or
8 continue to permit, customers who chose other suppliers to return as utility
9 generation customers; how transmission ownership and transmission
10 charges will change through the development of regional transmission
11 organizations (RTOs); and whether state and federal policy promoting
12 distributed generation will promote customer bypass of utilities. This all
13 means that investors no longer perceive electric utilities as "safe havens."
14 Investment risk has risen, and investors now require a higher return for
15 investing in the electric utility industry.

16
17 Q. Does PPL Electric face additional risks?

18 A. Yes, I believe it does. When the Company was an integrated utility
19 involved in the broad provision of generation, transmission, and distribu-
20 tion services, PPL Electric was able to spread the risks involved in any of
21 those businesses across a broader base. However, as a distribution
22 company now focusing on energy delivery, PPL Electric has all of its
23 assets concentrated in a single line of business and thus is fully exposed

1 to any risks, including those pertaining to size and scope, that may impact
2 its core business. In addition, PPL Electric can no longer control the
3 ultimate cost to the customer because of the loss of integration. This
4 creates a greater risk that it will not be able to respond to competition.

5

6 Q. Please discuss the earnings risk of being concentrated in a single line of
7 business.

8 A. A single-business company would face financial exposures with which an
9 integrated company would not necessarily have to contend. One segment
10 of the business would typically be able to tap the broader financial
11 resources of the corporation when facing financial difficulty. The distribu-
12 tion utility may still face public and political scrutiny for generation-related
13 problems that are now beyond the utility's control. The distribution utility, if
14 it continues to have any retail generation supply obligations, is more
15 reliant on the suppliers of that power than it was when it owned and
16 operated its own generating facilities. The loss of a major supplier of
17 generation services could pose a real financial threat to the distribution
18 utility that an integrated company, with a much broader base of revenues
19 and resources, would be in a better position to manage.

20 A related risk is the uncertainty surrounding price recovery of power
21 supplies connected to default service obligations. In the absence of rules
22 governing such recovery, the distribution company, which is still required
23 to serve as a provider of last resort, could face extreme financial distress.

1 An additional risk is heightened economic sensitivity due to
2 geographic concentration. As an integrated company, the Company
3 owned generation assets. During a recessionary period in Pennsylvania,
4 PPL Electric could face a decrease in load growth, or even a decline in
5 distribution revenues. If the Company still owned generation, it might
6 have been able to offset some of that shortfall by selling power into the
7 wholesale market. As a distribution company, PPL Electric would be
8 exposed to the economic situation with no potential to offset it.

9
10 Q. Are there other risks involving single line of business concentration?

11 A. Yes. Another set of risks pertains to advances in technology. One such
12 issue is distributed generation, which is a technology that permits power to
13 be generated on small-scale machines that can be sited near a manufac-
14 turing facility, in a commercial business or even a residence. Distributed
15 generation potentially can have a serious adverse impact on a utility's
16 delivery system because distributed generation can facilitate bypass of the
17 system. To the extent that customers see distributed generation as a
18 means of controlling their reliability and power quality, even in areas
19 where the utility (such as PPL Electric) provides high reliability and quality,
20 they may choose distributed generation in an effort to take more of their
21 operations under their own control. The extent of the risk depends largely
22 on factors beyond the utility's control (economics of production and
23 installation of distributed generation, and the extent of governmental

1 support, for example), and it is unknown how many customers will choose
2 bypass or when the loss will occur. However, in light of an event such as
3 the massive blackout of August 14, 2003 and the attendant widespread
4 concerns about system reliability, the bypass risk has likely increased.

5

6 Q. What other risks do you see technology posing to distribution utilities?

7 A. The advances in technology have made some industries less dependent
8 on geography. There will be continuing pressure to retain customers who
9 can relocate out of the utility's service area or who can take actions that
10 are equivalent to relocation. Manufacturers and commercial businesses
11 can choose to relocate to other parts of a state, or to other states or
12 regions. Bypass may increasingly become economic for these customers
13 as well as customers who do not wish to or cannot move. There will be
14 pressure to discount prices to retain these customers. PPL Electric no
15 longer controls the cost of power and may not be able to discount enough
16 to compete. Furthermore, the effect of lost customers is exacerbated for
17 companies such as PPL Electric. PPL Electric is a much smaller company
18 after generation divestiture and no longer has the balance sheet of an
19 integrated company on which to fall back, so its financial strength could be
20 stretched by customer loss. The Company simply has fewer units over
21 which to spread its fixed costs.

22

1 Q. You've discussed the mounting risks you see a distribution company
2 facing. Do those risks have the potential to reduce the company's
3 earnings and cash flow stream and increase their volatility?

4 A. Yes. A single line of business increases exposures to enterprise credit
5 risk, operating issues, prospective new costs, and technology issues, all of
6 which can have negative financial ramifications. Moreover, since these
7 factors are in large part beyond a company's control, the company's
8 investors have little guidance and more uncertainty. Uncertainty leads to
9 investor concern.

10

11 Q. How do institutional investors analyze their decisions whether to invest in
12 electric utilities?

13 A. Investors have a very large universe of stocks from which to select; with
14 few exceptions, they have no requirement to own electric utility stocks.
15 Institutional investors – financial institutions such as mutual funds, invest-
16 ment companies, insurance companies, commercial and investment
17 banks, and various types of public retirement funds – approach the
18 investment selection process from the standpoint of a portfolio. An
19 investment portfolio is a collection of stocks selected to achieve the
20 highest possible return within a commensurate level of risk. Therefore,
21 institutional investors only keep electric utilities in their portfolios when
22 such stocks contribute to achieving that risk/return relationship.

23

1 Q. How do individual investors make their investment decisions?

2 A. Individual investors typically seek stocks that will appreciate in value
3 and/or will provide dividend income. These investors frequently need
4 dividend income in anticipation of or actually funding retirement. Conse-
5 quently, the income aspect is particularly important to individual investors
6 of utility stocks, who comprise approximately 39% of PPL's shareholders.

7

8 Q. Why do institutional investors matter to PPL?

9 A. Institutional investors matter for three reasons. First, institutions, because
10 of the sheer size of their investment positions, can effectively direct the
11 course of individual securities, if not the market as a whole. So, as an
12 investor group, institutions warrant significant attention. Second, some of
13 the outstanding shares of PPL's common stock is held in "street name."
14 That is, the stock is registered in the name of a brokerage house, which
15 manages accounts for individuals or for organizations, such as public
16 retirement funds. "Street name" accounts are instances in which an
17 investment institution is directly transacting for individuals or an organiza-
18 tion serving individuals' financial interests. Third, it should be remem-
19 bered that the customers of institutional investors are individuals. Anyone
20 who has a stake in a retirement plan, owns a mutual fund, or has a trust
21 fund, for example, is directly or indirectly a client of an institutional
22 investor. Ultimately, it is the interests of individuals whom institutional
23 investors seek to serve.

1

2 Q. Why do investors, and in particular institutional investors, matter in a
3 consideration of a utility's rate of return?

4 A. A company's ability to raise capital in the financial markets impacts its
5 ability to do business. When the value of its stock – its currency – is
6 considered to be low, its cost of capital is increased. Investors are
7 constantly assessing the fundamentals of companies. When they
8 perceive a diminishment in a company's fundamentals – or even the
9 potential for one – they begin to require more compensation for the
10 greater risk present in their investment. Generally, this results in a lower
11 stock price that, with an unchanged dividend rate, provides a higher yield.
12 The effect of the reduced stock price on the company is a higher cost of
13 capital. The authorized return on equity is also one determinant of the
14 Company's free cash flow. This in turn is a determinant of the Company's
15 credit ratings, which will affect the Company's cost of borrowing. PPL
16 Electric will face substantial expenditures to expand and upgrade its distri-
17 bution infrastructure over the next few years. If the Company's debt
18 ratings were to deteriorate, PPL Electric would face a higher cost for those
19 borrowings.

20

21 Q. Why might an institutional investor choose not to invest in a particular
22 electric utility?

1 A. Several factors might be drivers. First, institutional investors have fiduciary responsibilities. For example, managers of pension assets are overseen by the ERISA law, which mandates that a portfolio manager behave as a so-called "prudent man." That is to say, he or she is expected not to make investment decisions that are unduly risky. Or in the case of mutual funds, boards of directors are charged with ensuring that the funds' investment charters are met. Second, institutional investors have performance pressures. It is not enough for stocks in a portfolio simply to increase in value. Rather, *relative performance is what counts*. Investment performance is gauged against a market proxy (such as the Standard & Poor's 500 Index) or a peer group of investors (i.e., investors with a similar style, such as value, growth, growth & income, small cap, etc.). Organizations such as Morningstar track and publicize the relative performance for mutual funds, and various pension consultants perform the same service for their client organizations.

16

17 Q. What happens when an institutional investor underperforms?

18 A. *The results can vary, but eventually, underperformance is likely to result in* lost business. Mutual fund shareholders can sell their fund shares. A pension plan sponsor can fire the professional investor or reduce the assets under the investor's management. And, of course, poor performance also disadvantages the individual, who has entrusted his monies to the institution for management.

1

2 Q. How long a period does an institutional investor have before performance
3 becomes an issue?

4 A. *Again, it can vary. But there is little argument that institutional investors*
5 *no longer have the luxury of a long time horizon in which to show perform-*
6 *ance. Investors want results. And with the public visibility that investment*
7 *results now have (through the auspices of such organizations as*
8 *Morningstar and the various pension consultants) and the resulting*
9 *performance pressure, most investment organizations are now operating*
10 *with a much shorter time horizon than in years past. Generally speaking,*
11 *a long investment time horizon today can be as short as 12-18 months.*
12 *So, a stock that is unlikely to perform within the prescribed time horizon is*
13 *usually not attractive for purchase or continued investment by an institu-*
14 *tional investor.*

15

16 Q. Do all institutional investors function within the time frames you describe?

17 A. No. There is a type of institutional investor called a hedge fund that
18 frequently buys and sells the same stock during the course of a day.

19

20 Q. With that kind of investment behavior, what impact do hedge funds have
21 *on the market in general and stocks in particular?*

22 A. Their impact can be dramatic. Hedge funds are well known for trading in
23 information; their actions are frequently event-driven. Sometimes that

1 information is factual and other times it falls into the category of rumor.
2 Because investors at these funds have wide information networks and are
3 in frequent communication with companies and a broad range of other
4 investors, they have the ability and the power to create volatility, which in
5 turn impacts the movement of stock prices. And because the number of
6 hedge funds participating in the market as well as the funds' assets have
7 grown exponentially in recent years – recent estimates put the numbers at
8 over 5300 firms with assets of \$619 billion during the first quarter of 2003,
9 up from 610 firms with \$39 billion in assets in 1990 – they have become a
10 very strong force both in the market and in stocks in which they are
11 interested. When they like an industry group or a stock, hedge funds can
12 provide substantial support to stock prices. But conversely, when they
13 become disenchanted, their tendency is to sell quickly and without
14 remorse. Although their focus is not on contributing to orderly markets,
15 hedge funds are a formidable presence in the market place and must be
16 reckoned with.

17
18 Q. Can you give an example of how hedge funds might traffic in PPL's stock?

19 A. Yes. In 2003, PPL announced its intention to file the current rate case.
20 Hedge funds assuredly made assumptions about the details of the case,
21 including its resolution, prior to the filing. If, when the Commission's
22 decision is ultimately announced, the details fall short of those
23 expectations, the hedge funds could put significant pressure on the stock

1 either through outright sales, or short-selling, i.e., selling stock that is
2 borrowed.

3

4 Q. What is the significance for regulators in Pennsylvania and elsewhere of
5 the reduced time horizons for valuing stocks now used by institutional
6 investors and hedge funds?

7 A. The increased rapidity with which institutional investors and hedge funds
8 make investment decisions means their judgments will immediately reflect
9 actions by utility regulators that are perceived to have a short-term or long-
10 term impact on the utility's financial performance. Thus, for example, a
11 rate order that contains a lower than expected allowed return on equity
12 could be viewed as a reason to sell the utility's stock due to the impact on
13 earnings. Similarly, institutional investors and hedge funds are not likely
14 to act to purchase or to hold the stock of a utility that has received a regu-
15 latory order that promises only the uncertainty of "future" benefits. In sum,
16 the presence of institutional investors and hedge funds whose relatively
17 short time horizons are significant factors in the liquidity of utility common
18 stocks means that regulatory orders are likely to have an immediate
19 impact on the price of those stocks.

20

21 Q. Have any institutional investors recently expressed opinions regarding
22 PPL Electric's Pennsylvania rate filing?

1 A. Yes, they have. Goldman Sachs wrote:

2 "PPL has pending rate proceedings that will reset rates for its
3 Pennsylvania distribution business beginning 1/1/2005 and its UK
4 distribution business beginning 4/1/2005. Management intends to
5 submit its Pennsylvania rate application by the end of Q1 2004.
6 Earnings upside from the rate review could be substantial, with
7 approval of even a low 10.5% ROE potentially adding \$0.45 to
8 earnings.

9 January 28, 2004 report: "PPL (OP/N): Stock Still attractive
10 at current levels"
11

12 And Merrill Lynch offered an opinion, as well:

13
14 "In Spring 2004, PPL will file a rate case in Pennsylvania. The
15 utility has been earning a low single digit ROE. Rate relief to earn a
16 reasonable 10-12% ROE would add \$0.30/sh to EPS. New rates
17 go into effect on 1/1/2005.

18 January 29, 2004 report: "PPL Corp.: Visible Growth Beyond
19 "2004."
20
21
22

23 And Morgan Stanley also weighed in:

24
25 "PA utility earning less than 5% ROE – But assuming rate relief is
26 granted that will allow at least a 10% ROE, we calculate
27 incremental EPS of \$0.30 in 2005. PPL plans to file its rate case
28 3/31, with new rates effective 1/05."

29 February 2, 2004 report: "PPL Corp.: Solid Earnings, Raising
30 Target; 2004 Rate Case Year"
31
32
33

34 Q. What conclusions do you draw from these comments about institutional
35 investors' perceptions regarding PPL Electric's rate filing?

36 A. I believe investors are expecting the Company to be granted a ROE in a
37 range of 10-12%, with the bias toward the upper end of that range, as

1 evidenced by Merrill Lynch's expectation of a ROE range of 10-12% and
2 Goldman Sachs' reference to "even a low 10.5% ROE."

3

4 Q. In the current low interest rate environment, do you consider investor
5 expectations regarding the Company's prospective ROE award to be
6 reasonable?

7 A. Yes, I do. Although interest rates are at historically low levels, that factor
8 is not the only one that investors are taking into account. I believe that
9 because of the greater risks that the industry in general and distribution
10 companies in particular are facing, investors are requiring a greater risk
11 premium on their utility investments. Thus, I think that the broader interest
12 rate environment should not be considered in isolation in terms of estab-
13 lishing ROEs for utility companies.

14

15 Q. Are there additional factors regarding investors' expectations regarding
16 the Company's prospective ROE award?

17 A. Yes. Investors have a high opinion of the quality of Pennsylvania regula-
18 tion. In a recent report, Lehman Brothers provided a ranking of state utility
19 commissions from an investor perspective. The firm ranked Pennsylvania
20 "Tier 2" on a 5-tiered scale, with Tier 1 being "Most Shareholder Oriented"
21 and Tier 5 being "Most Consumer Oriented." It bears mention that only 7
22 other states appeared in the Tier 2 level, and 6 states in the Tier 1
23 ranking. Lehman's rankings were based on 6 criteria:

1 "1) elected versus appointed commissions; 2) PBR mechanism or
2 not; 3) allowed ROEs; 4) *Settle vs. Litigate*; 5) rate levels; and 6) a
3 subjective investor friendless rating."

4 March 5, 2004 report: "They're Back! Twenty-Six Rate
5 Cases This Year Give Rise to the Regulators"
6

7 A disappointing ROE in the Company's rate case could signal a change in
8 the positive regulatory environment enjoyed in Pennsylvania, and
9 investors' opinions would be altered accordingly.

10
11
12 Q. In your experience as an analyst and portfolio manager, could a perceived
13 change in a company's regulatory climate affect your investment opinion?

14 A. Absolutely. During my tenure as an active investor, the quality of a
15 company's regulatory environment was a critical factor in my assessment
16 of its investment attractiveness. An adverse regulatory decision could be
17 a key determinant in my recommendation or decision to sell a stock
18 already owned or to not make an investment in one under consideration. I
19 believe that investors selecting stocks today still place a very high value
20 on constructive regulation. And with a new round of base rate case filings
21 underway in the industry, I think it likely that the quality of regulation will
22 receive renewed investor attention.

23
24 Q. What role do credit agencies play in investors' expectations?

25 A. In the wake of financial disasters, bankruptcies, and the ensuing severe
26 erosion in investor confidence in the past few years, credit issues have

1 become critically important not only to fixed income investors, but also to
2 equity investors. While credit downgrades initially impacted only the most
3 troubled companies, a spillover effect soon was seen on healthy utilities.
4 Part of this was due to the fact that the rating agencies, responding to
5 harsh criticism that they had failed to catch problems early enough in
6 companies such as Enron Corp., began to heighten their scrutiny of all
7 entities under their watch and became far more proactive in making rating
8 changes. As well, "headline risk" began to come into play, as investors
9 worried that any company could be vulnerable to a downgrade. Thus,
10 equity investors now watch closely the actions of the credit agencies,
11 because any change in ratings can have a significant impact on a
12 company's stock price.

13
14 Q. What happens when a credit downgrade occurs?

15 A. In the simplest terms, it becomes more expensive for a company to raise
16 money in the capital markets because a downgrade raises a company's
17 risk profile and consequently increases the cost of debt. And because of
18 the increased linkage these days between ratings and stock prices, the
19 price frequently reacts – sometimes quite strongly – to a downgrade. For
20 example, Moody's Investors Service cut the ratings of Allegheny Energy
21 and its subsidiaries to "junk," or below investment-grade, status on
22 October 1, 2002. The prior day, September 30, Allegheny's stock price
23 closed at \$13.10. By October 8, when the company announced that it was

1 in technical default with creditors due to its inability to meet higher
2 collateral requirements prompted by the downgrade, the stock closed at
3 \$3.80. Thus, in the space of a week, Allegheny's stock price – and the
4 value of a shareholder's investment – lost 71% of its value.

5
6 Q. How do the rating agencies view PPL Electric, and in particular, the rate
7 case?

8 A. A recent written report on the company came from Standard & Poor's,
9 which rates the Company A-, with a negative outlook. At the end of last
10 year, the agency wrote:

11 "The company has announced its intention of filing for a rate
12 increase by April 2004 for the post-2004 period. However, the
13 outcome of such a rate case is uncertain. Ratings are predicated
14 on its ability to maintain cash flow coverages and debt-to-capital
15 ratios at levels of about 3.0x to 3.1x and 53% to 55%, respectively,
16 and also on the outcome of the imminent rate case before the PUC.
17 If the PUC does not allow any rate increase, PPLEU's ratings will
18 be lower. PPLEU's credit metrics are weaker than estimated for
19 2003 and are likely to be weak through 2004 due to the rate cap.

20
21 The negative outlook also reflects PPLEU's need to improve its
22 returns to maintain its financial position."

23 --December 30, 2003 report: "Summary: PPL Electric
24 Utilities Corp."

25
26
27 Q. Please elaborate on why the earnings stream is important in stock selec-
28 tion.

29 A. Earnings growth is an important component of what will drive stock price
30 appreciation and dividend income. A company with a higher growth rate
31 will typically warrant a higher price/earnings (P/E) ratio than other

1 companies. The reverse also holds true. In the end, an institutional
2 investor wants to select the optimal choices for inclusion in a portfolio, so
3 the concept of relative valuation is very important. Stocks are always
4 viewed in terms of how well they stack up against other investment
5 alternatives, including holding cash. And another reason why earnings
6 are important is that they underpin the dividend. Without earnings growth,
7 the dividend cannot grow.

8

9 Q. Do you believe that an ROE of 11.50% for PPL Electric is consistent with
10 investors' expectations?

11 A. Yes, I do. As noted in the previous discussion on institutional investors'
12 current views of the company, I believe that investors are expecting PPL
13 Electric to be granted a ROE in a range of 10%-12%, with the bias toward
14 the upper end of that range. Investment risk in the electric utility industry
15 is higher than it has been, and investors are requiring higher compensa-
16 tion to assume that added risk. As an input in valuation models, earnings
17 levels logically translate into the attractiveness of a stock, other factors
18 being equal. A reasonable ROE award should sustain the Company's
19 earnings power and affect the potential for future dividend growth.

20 Conversely, a lower ROE could potentially undermine investors' expecta-
21 tions for ongoing dividend growth. Further, an 11.5% ROE would be
22 consistent with recent awards in electric utility rate cases. As Lehman
23 Brothers' March 5 report, "They're Back!" details, the average ROE

1 granted in 2003 within the industry was 10.96%. By quarters, the figures
2 were 11.49% (1Q), 11.16% (2Q), 9.95% (3Q), and 11.48% (4Q).

3

4 Q. Turn now, please, to the testimony filed by Paul Moul. Would you please
5 comment on his ROE recommendation?

6 A. Mr. Moul recommends that PPL Electric be granted an 11.5% ROE. His
7 conclusion was based on a variety of well-established financial models as
8 well as comparative peer group assessment. His finding of an 11.5%
9 ROE is consistent with investor expectations.

10

11 Q. Does this complete your testimony?

12 A. Yes.

13

APPENDIX A

JULIE M. CANNELL
P.O. Box 199
Purchase, New York 10577

BUSINESS EXPERIENCE:

1997- J.M. CANNELL, INC.

President of firm providing advisory services specializing in the electric utility industry.

1977 - 1997 LORD ABBETT & COMPANY, New York, New York

1995 - 1997 Equity Portfolio Manager. Responsibility for management and client servicing of ten institutional equity portfolios with total assets in excess of \$700M. Actively and successfully involved in new institutional business marketing effort.

1994-1996 Associate Director of Equity Research. Provided oversight of departmental activities, including supervision of analysts' research efforts and support staff functions.

1992-1995 Portfolio Manager, America's Utility Fund. Full portfolio management responsibility for the fund since its May 1992 inception.

1978-1995 Securities Analyst. Sole responsibility for analysis of and stock recommendations for the electric utility and telecommunications industries. Other areas of coverage previously included housing (2 years) and pollution control (1 year).

Summer 1977 Research Assistant in Utilities.

1973-1976 UNIVERSITY OF COLORADO, Colorado Springs, Colorado.

Public Services Librarian
Instructor in Bibliography to undergraduate and M.B.A. students

1971-1973 CAMERON COLLEGE, Lawton, Oklahoma.

Reference Librarian

EDUCATION:

1978	COLUMBIA UNIVERSITY, MBA - Finance
1971	EMORY UNIVERSITY, M.Ln. - Librarianship
1970	MARY BALDWIN COLLEGE, B.A. - English

MEMBERSHIPS:

Chartered Financial Analyst (C.F.A.)
New York Society of Security Analysts
Association of Investment Management &
Research
Wall Street Utility Group

Pennsylvania Public Utility Commission

v.

PPL Electric Utilities Corporation

Docket No. R-00049255

Rebuttal Testimony of
PPL Electric Utilities Corporation

July 27, 2004

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ja
8/9/04

DOCUMENT

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00049255

RECEIVED

AUG 24 2004

**PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU**

PPL Electric Utilities Corporation

DOCKETED
AUG 25 2004

Statement No. 2-R

Direct Testimony of Joseph R. Schadt

1 Q. Please state your name and business address.

2 A. My name is Joseph R. Schadt. My business address is PPL Services
3 Corporation, Two North Ninth Street, Allentown, Pennsylvania, 18101.

4
5 Q. Did you previously submit testimony in this proceeding on behalf of PPL Electric
6 Utilities Corporation?

7 A. Yes. I submitted my direct testimony (Statement No. 2) on March 29, 2004.

8
9 Q. What is the purpose of your rebuttal testimony?

10 A. My rebuttal testimony responds to the assertions of witnesses on behalf of the
11 various intervenors on the following topics:

12 (I) the reduction in the claim for post retirement benefits other than
13 pensions (responding to Messrs. Weakley and Morgan);

14 (II) the reduction in the claim for pension expense (responding to Messrs.
15 Weakley and Morgan);

16 (III) *the adjustments in the claim for Automated Meter Reading (AMR)*
17 *displacement costs (responding to Messrs. Catlin, Weakley and*
18 *Epstein);*

19 (IV) the elimination of the amortization claim for expiring amortization for the
20 Power Management System Software and Deferred Taxes Related to
21 the Cost of Removal Expense (responding to Messrs. Morgan and
22 Weakley);

23 (V) the adjustment to the claim for rate case communication costs
24 (responding to Mr. Weakley);

25 (VI) the reduction in the claim for Community Affairs (responding to Messrs.
26 Morgan and Weakley);

- 1 (VII) the removal of On-Track arrearage forgiveness included in Uncollectible
2 accounts expense presumed to also be included in On-Track Program
3 costs (responding to Mr. Weakley);
- 4 (VIII) the normalization of FERC accounts 588 and 593 (responding to Mr.
5 Weakley);
- 6 (IX) the adjustment to the environmental remediation expense claim
7 (responding to Messrs. Morgan, Weakley, Prisco, McCormick and
8 Epstein);
- 9 (X) the adjustment to increase late payment revenue which would lower the
10 Company's revenue requirement (responding to Mr. Gruber);
- 11 (XI) the adjustment to the claim for injuries and damages based on the
12 Company's historical amount for 2003 (responding to Mr. Prisco);
- 13 (XII) the adjustment for self funded health insurance (responding to Mr.
14 Prisco), and
- 15 (XIII) the recommendation to align and incent a portion of executive
16 compensation with "rate payers interest" and have executive
17 compensation be indexed to reliability, community investment, and
18 customer satisfaction (responding to Mr. Epstein).

19
20 **I. Post Retirement Benefits Other than Pensions (SFAS No. 106)**

21 Q. Please describe the adjustments to the claim for post retirement benefits other
22 than pensions proposed by Mr. Weakley and Mr. Morgan.

23 A. Mr. Weakley and Mr. Morgan recommend reducing the expense claim for post
24 retirement benefits other than pensions. Mr. Weakley also recommends
25 reducing rate base. PPL Electric's total cost of post retirement benefits other
26 than pensions in this proceeding is \$13,916,000. The operating expense portion
27 of the claim, \$9,672,000, is based on an estimate prepared by PPL's actuarial

1 consultant in October 2003. On March 30, 2004, the actuary updated the
2 calculation of post retirement benefits other than pensions for 2004. The
3 calculation indicated that 2004 costs would be less than the original estimate.
4 The expense adjustments proposed by Mr. Weakley and Mr. Morgan are based
5 on the March 2004 update of the calculation for 2004 submitted in response to
6 Question 16 of Interrogatories of the Office of Consumer Advocate, Set X, dated
7 May 20, 2004.

8
9 Q. Do you agree with the adjustments proposed by Mr. Weakley and Mr. Morgan?

10 A. No, I do not agree. The March 2004 calculation assumed that union and non-
11 union employees would be subject to the same cost sharing mechanism for
12 retiree health care. In June 2004, PPL Corporation learned this assumption
13 would violate the terms of its bargaining unit contract. As a result, in July 2004
14 the actuary prepared a corrected calculation for 2004. Based on the corrected
15 calculation for 2004, PPL Electric's cost for post retirement benefits other than
16 pension is \$14,314,000, or \$398,000 more than the original estimate; the
17 expense claim is \$9,948,000, or \$276,000 more than the original estimate. The
18 letter from the actuary describing the error is attached as Exhibit JRS1 to my
19 rebuttal testimony. Accordingly, the adjustments proposed by Mr. Weakley and
20 Mr. Morgan should be rejected.

21
22 Q. Has the Company previously informed the parties to this proceeding of these
23 changes?

24 A. Yes. On July 15, 2004, supplemental responses to the following Interrogatories
25 were filed:

- 26 • Question OTS-RE97 of Interrogatories of the Office of Trial Staff, Set 7,
27 dated April 27, 2004.

- 1 • Question 15 of Interrogatories of the Office of Consumer Advocate, Set X,
2 dated May 20, 2004.
- 3 • Question 16 of Interrogatories of the Office of Consumer Advocate, Set X,
4 dated May 20, 2004.

5 6 II. Pension Expense

7 Q. Mr. Morgan recommends an adjustment of \$489,000 to pension expense to
8 reflect PPL Corporation's final 2004 actuarial report and an adjustment of
9 \$36,000 to the Company's 2004 Supplemental Executive Retirement Plan
10 (SERP) claim. The \$36,000 adjustment represents a 10% reduction in the SERP
11 claim.

12 A. I agree with Mr. Morgan's recommended decrease of \$489,000 to PPL Electric's
13 pension expense. I do not, however, agree with the \$36,000 reduction to the
14 SERP claim, but would instead agree to a \$30,000 reduction in the SERP claim.
15 At the time of budget preparation, PPL Corporation did not receive an actuarial
16 report to support its SERP expense. Instead, PPL Corporation used the prior
17 year costs as the basis for its budget and made an adjustment to reflect changes
18 in discount rates between the two years. In March of 2004, the Company
19 received the actuarial estimate for SERP expense that supports a \$30,000
20 reduction in the claimed SERP expense. Based on this information, PPL Electric
21 would recommend a \$30,000 reduction in its SERP expense claim.

22
23 Q. Mr. Weakley recommends that the Commission reject PPL Electric's claim for
24 pension expense. Mr. Weakley believes pension expense should be based on
25 cash contributions to the pension fund, rather than the actual pension expense
26 recorded in compliance with Statement of Financial Accounting Standards No. 87
27 Employers' Accounting for Pensions ("SFAS No. 87").

1 A. I disagree with Mr. Weakley's recommendation. Using SFAS No. 87 as the basis
2 for the pension expense claim is consistent with the Commission's order in PPL
3 Electric's last base rate proceeding at Docket No. R-00943271. SFAS No. 87
4 requires accrual accounting for pensions and provides reasonably stable pension
5 expense from year-to-year, resulting in more stable rates for the Company's
6 customers. Rates based on cash contributions can result in dramatic
7 fluctuations. Using pension costs calculated in accordance with SFAS No. 87
8 provides consistency with revenues and other expenses included in PPL
9 Electric's claim in this proceeding, which also are based on the accrual method of
10 accounting. Using SFAS No. 87 for ratemaking also provides consistency in PPL
11 Electric's accounting and reporting for pension expense from both generally
12 accepted accounting principles (GAAP) and regulatory perspectives.

13
14 **III. AMR Displacement Costs**

15 Q. Please describe the AMR Displacement Costs.

16 A. The cost of displacing employees as a result of the AMR Program was recorded
17 as a pension special termination benefit charge for the benefits to be paid to
18 separated employees, including enhanced early retirement benefits and one-time
19 special pension separation allowances that will be paid from the PPL Retirement
20 Plan pension trust. The pension special termination benefit charge of \$8.8
21 million was actuarially calculated under the provisions of Statement of Financial
22 Accounting Standards No. 88 "Employers' Accounting for Settlements and
23 Curtailments of Defined Benefit Pension Plans and for Termination Benefits"
24 ("SFAS No. 88"). The entire charge was recorded in the third quarter of 2003, at
25 which time the final determination of terminations expected for the completion of
26 the program was made.

1 Q. Please describe the adjustments for AMR Displacement costs proposed by
2 Mr. Catlin, Mr. Weakley, and Mr. Epstein.

3 A. Mr. Catlin, Mr. Weakley and Mr. Epstein recommend that recovery of the AMR
4 displacement costs not be allowed.

5
6 Q. What is the basis of Mr. Catlin's recommendation to not allow recovery of AMR
7 displacement costs?

8 A. Mr. Catlin's testimony contains three reasons for his recommendation. First, Mr.
9 Catlin states that counsel advised him that allowing these costs to be amortized
10 and recovered subsequent to the rate cap would constitute a de facto rate cap
11 exception in violation of the Competition Act and PPL Electric's restructuring
12 settlement. Second, he states that allowing PPL Electric to amortize the pension
13 benefit termination charge in rates would result in ratepayers bearing costs which
14 exceed the benefits of the AMR program. Third, he states that the expense
15 accrual did not require a cash outlay by PPL and that PPL Electric may never be
16 required to make a cash contribution to fund this expense.

17 Q. Do you agree with Mr. Catlin's recommendation?

18 A. No, I do not. First, permitting recovery of these costs in prospective rates to be
19 effective beginning January 1, 2005, does not change rates in effect through
20 December 31, 2004, and, I am advised by counsel, is not a violation of the
21 Competition Act and PPL Electric's restructuring settlement, as alleged by Mr.
22 Catlin. The Competition Act and settlement do not address the setting of
23 distribution rates beyond 2004. Second, Mr. Krall, in Statement No. 4-R, refutes
24 Mr. Catlin's statement that allowing PPL Electric to amortize the pension benefit
25 termination charge in rates would result in ratepayers bearing costs which exceed
26 the benefits of the AMR program. Third, regarding Mr. Catlin's comment on cash
27 outlay, cash funding of these costs, which have been or will be paid by the PPL

1 Retirement Plan, is subject to the rules of the Internal Revenue Service. Under
2 these rules, cash contributions can be highly variable and can result in dramatic
3 fluctuations. In my view, rate making for this pension special termination benefit
4 charge should be consistent with that for SFAS No. 87.
5

6 Q. What is the basis of Mr. Weakley's recommendation to not allow recovery of
7 AMR displacement costs?

8 A. Mr. Weakley states that the claim will be paid by the pension trust and ratepayers
9 already have paid these costs through past pension expenses included in rates.
10

11 Q. Do you agree with Mr. Weakley's recommendation?

12 A. No, I do not. Mr. Weakley's statement that the claim will be paid by the pension
13 trust and ratepayers have already paid these costs through past pension
14 expenses included in rates is simply not true. Pension costs granted in the last
15 base rate case were calculated on the basis of normal pension costs in
16 accordance with SFAS 87. The AMR displacement costs are incremental costs
17 not contemplated within the provisions of SFAS No. 87. These costs were
18 actuarially determined under the provisions of SFAS No. 88, and must be
19 recovered independently of normal SFAS 87 pension costs.
20

21 Q. What is the basis of Mr. Epstein's recommendation to not allow recovery of AMR
22 displacement costs?

23 A. Mr. Epstein asserts, among other things, that ratepayers should not pay PPL
24 Electric to displace, reduce or terminate workers and should not have to fund
25 Company layoffs and underwrite the costs of a program that will yield little net
26 benefit to customers.
27

1 Q. Do you agree with Mr. Epstein's recommendation?

2 A. I do not agree. Mr. Epstein states conclusions without supporting evidence. I
3 would like to point out that the Commission granted recovery of the costs of the
4 Voluntary Early Retirement Program ("VERP") in PPL Electric's last base rate
5 case at Docket No. R-00943271. In addition, the Company's claim for operation
6 and maintenance expense in this proceeding includes the cost savings
7 associated with the displaced employees. Schedule 5 of Exhibit Future 1 sets
8 forth a decrease of \$5,950,000 in T&D-related wages, taxes and benefits for the
9 future test year.

10
11 **IV. Expiring Amortization**

12 Q. Mr. Morgan and Mr. Weakley each recommend eliminating the amortization claim
13 for the Company's Power Management System Software of \$529,587. The basis
14 for their recommendation is that 2004 is the last year of the five-year amortization
15 period over which the Company expensed the costs of the software and because
16 the rates from this proceeding go into effect on January 1, 2005, the cost will
17 have been fully amortized.

18 Mr. Morgan also recommended eliminating the amortization of deferred taxes
19 related to the cost of removal expense of \$177,000 because these costs will also
20 be fully amortized as of the end of 2004.

21 A. The Company agrees with eliminating the amortization claim for the Power
22 Management System Software since the amortization expires in 2004 and the
23 Company has no plans to purchase any other capitalized software that would be
24 amortized in 2005.

25 The Company does not agree with eliminating the amortization of deferred
26 taxes related to the cost of removal expense of \$177,000. On July 15, 2004, the
27 Company issued a supplemental response to Question 53 of Interrogatories of

1 the Office of Consumer Advocate, Set III, dated April 27, 2004. In the
2 supplemental response, the Company corrected the \$177,000 debit amount to a
3 credit amount, and changed the remaining years of amortization from zero years
4 to 1.6 years. The 1.6 years was calculated by dividing the December 31, 2003
5 remaining balance to be amortized of \$284,000 by the 2004 amortization of
6 \$177,000. Because the amortization does not expire in 2004, the Company's
7 claim of \$177,000 is correct and should be allowed.

8 9 V. Rate Case Communications Costs

10 Q. Please describe the adjustments for rate case communications costs proposed
11 by Mr. Weakley.

12 A. Mr. Weakley recommends that the claim for rate case communications costs of
13 \$130,000 be rejected.

14
15 Q. What is the basis of the proposed adjustments?

16 A. Mr. Weakley believes the expense is a non-recurring expense.

17
18 Q. Do you agree that the expense is non-recurring?

19 A. Yes, I agree that the expense is non-recurring. However, even though it is a non-
20 recurring cost, the Company should be allowed to collect the amount as a normal
21 rate case expense. It appears that the confusion over this expense may result
22 from the mechanics of the Company's request to recover the rate case expense.

23 In preparation of the rate case filing, PPL Electric anticipated \$2,000,000 in
24 rate case expenses associated with the case. The \$2,000,000 of anticipated
25 expenses includes \$1,000,000 of budgeted expenses by PPL Services (including
26 \$130,000 budgeted by External Affairs) and \$1,000,000 of expenses for legal
27 fees, witnesses and other costs which were unbudgeted. The Company

1 proposed amortizing the total anticipated rate case expenses of \$2,000,000 over
2 a two-year period, resulting in annual amortization of \$1,000,000. Because this
3 annual amortization of \$1,000,000 equals the budgeted rate case expenses of
4 \$1,000,000 for PPL Services, no additional adjustment is appropriate to rate case
5 expenses or PPL Services expenses.
6

7 VI. Community Affairs

8 Q. Mr. Morgan and Mr. Weakley each recommended a reduction in the claim for
9 Community Affairs expense from \$800,000 to \$500,000 because the budgeted
10 amount should have been \$500,000 as per the Company's response to Question
11 OTS-RE-86 of Interrogatories of the Office of Trial Staff, Set 7, dated April 27,
12 2004.

13 A. The Company agrees with the proposed reduction of \$300,000, because the
14 budgeted amount should have been \$500,000.
15

16 VII. On-Track Arrearage Forgiveness

17 Q. Mr. Weakley recommends the \$3.7 million for On-Track arrearage forgiveness,
18 included in Account 908, as shown on Schedule B-4 of Exhibit Future 1, be
19 removed from the Company's uncollectible accounts expense claim because it
20 also is included in the Company's future test year claim of \$14.7 million for its
21 On-Track Program costs. Mr. Weakley alleges that PPL Electric has double-
22 counted the On-Track arrearage forgiveness in the future test year claim. Is this
23 adjustment appropriate?

24 A. No, this adjustment is not appropriate. Mr. Weakley is correct that the \$3.7
25 million for On-Track arrearage forgiveness is included in the \$14.7 million claim
26 for On-Track Program costs, as shown on Schedule D-8, Adjustment for
27 Increased Cost of Social Programs, of Exhibit Future 1. However, Mr. Weakley is

1 incorrect in asserting that PPL Electric has double-counted the On-Track
2 arrearage forgiveness. Schedule D-8 compares the Company's total proposed
3 social program costs of \$26,289,000 (which includes \$3.7 million for On-Track
4 arrearage forgiveness) to the \$21,513,000 included in the 2004 budget for these
5 programs (which also includes \$3.7 million for On-Track arrearage forgiveness in
6 Account 908, Customer Assistance Expenses.) The net effect of the comparison
7 for On-Track arrearage forgiveness is zero, since it is included in both the
8 proposed costs and the budget. PPL Electric's response to Question OTS-RE-
9 67 of Interrogatories of the Office of Trial Staff, Set 5, dated April 23, 2004
10 identifies the accounts on Schedule B-4 that contain the cost of social programs.
11 Account 908, Customer Assistance Expenses is included in that response.
12 Account 904, Uncollectible accounts, was not included in the response and does
13 not contain the \$3.7 million of On-Track arrearage forgiveness. In summary, the
14 \$3.7 million for On-Track arrearage forgiveness has not been double-counted
15 and accordingly, Mr. Weakley's recommendation should be rejected.

16 17 **VIII. Normalization of FERC Accounts 588 and 593**

18 Q. Mr. Weakley recommends that the Company's claim for FERC Account 588 and
19 FERC Account 593 be normalized by averaging the actual expenses incurred
20 through 2001 and 2003, adjusted for inflation. Is this appropriate?

21 A. PPL Electric does not believe it is appropriate to select and normalize the claim
22 for certain FERC accounts for two primary reasons. Mr. Weakley provided no
23 justification for the use of a 3-year average that reduced expense by \$4,043,000.
24 Given the nature of these accounts, a 5-year average may better capture the
25 variability between years and therefore be more appropriate. The use of a 5-year
26 average of these expenses would result in a \$1,725,000 adjustment for
27 normalization of these two accounts.

1 Second, the accounts selected appear arbitrary. In his testimony, Mr.
2 Weakley provided no justification for the selection of Account 588, Miscellaneous
3 Distribution Expenses, or Account 593, Maintenance of Overhead Lines. It
4 should be noted that Question OTS-RE-141 of Interrogatories of the Office of
5 Trial Staff, Set 19, dated June 3, 2004, requested the historical amount of
6 expenses recorded for Accounts 588, 593, and 595. However, Mr. Weakley
7 chose to normalize only Accounts 588 and 593. If Account 595, Maintenance of
8 Line Transformers, also was included in this normalization exercise, PPL Electric
9 would be able to increase its claim for Account 595 by \$353,000.
10

11 Q. Mr. Schadt, do you have any other comments about the level of total distribution-
12 related expenses claimed in this filing?

13 A. Yes. During the discovery process, there have been numerous inquiries
14 requesting information as to why specific components of the test year O&M
15 expenses were higher than the same components in the historic test year. For
16 example, Mr. Epstein comments about increased use of "work by others" in his
17 rebuttal testimony. It is true that certain components of PPL Electric's O&M
18 expenses have increased. However, PUC-jurisdictional O&M expenses actually
19 have decreased by \$8.9 million between 2003 and 2004. This can be seen on
20 Schedules D-1 of Exhibits Historic 1 and Future 1, Column 6. The PUC-
21 jurisdictional O&M expense for 2003 and 2004 are \$318.7 million and \$309.8
22 million, respectively. This reduction in O&M expense between 2003 and 2004
23 clearly shows PPL Electric's commitment to minimizing its expense while
24 maintaining reliability and customer service.
25

26 **IX. Environmental Remediation Expense**

1 Q. Please describe the adjustments for environmental remediation expense
2 proposed by Mr. Morgan, Mr. Weakley, Mr. Prisco, Mr. McCormick and Mr.
3 Epstein.

4 A. Mr. Morgan proposes using a three-year average to derive an allowable amount
5 for environmental remediation expense. Mr. Weakley recommends that PPL
6 Electric's total claim of \$3,556,000 be disallowed. Mr. Prisco (1) questions if
7 ratepayers are responsible for remediation cost, (2) states that some of the
8 *properties may have been sold at a profit and the profit should be used to*
9 *mitigate the cost of remediation*, (3) states that it appears that the manufacturing
10 of gas would be more similar to generating electricity than transporting an end-
11 product, and (4) recommends amortizing the costs ultimately determined to be
12 born by distribution customers over several years. Mr. McCormick states that the
13 costs related to remediation at manufactured gas plants may be generation-
14 related costs improperly included in the proposed distribution rates. Mr. Epstein
15 states, among other things, that the projections are based on vague past
16 references overly dependent on the random selection of a single site and far
17 beyond what is necessary to complete the final phase of the PCB cleanup
18 project.

19
20 Q. What is the basis for their proposed adjustments?

21 A. The basis for their adjustments appears to be the view that environmental
22 remediation costs are not the responsibility of the Company, and that actual
23 expenditures do not support the claimed annual expense level of \$3,556,000.

24
25 Q. What is your conclusion regarding the adjustments proposed by Messrs. Morgan,
26 Weakley, Prisco, McCormick and Epstein?

1 A. These adjustments should be rejected. Before the advent of the interstate
2 natural gas pipeline system in the mid-1900's, various utility companies, including
3 predecessors to PPL Electric, supplied gas to its local customers by
4 manufacturing the gas from coal and petroleum products. Once the natural gas
5 pipeline transmission systems were developed, the utilities discontinued
6 manufacturing gas, but continued to operate the local distribution systems to
7 supply natural gas, rather than manufactured gas to its customers. Under state
8 and federal laws, PPL Electric may be wholly or partially responsible for the
9 remedial costs at these facilities. As a result, these assets remained with PPL
10 Electric during its restructuring in 1998.. Accordingly, Mr. Weakley's
11 recommendation that the total amount of the remediation claim be disallowed
12 should be rejected. Furthermore, because these facilities were used to serve gas
13 distribution customers at that time, Mr. Prisco's questioning of whether
14 ratepayers are responsible for remediation costs and his statement that it
15 appears that the manufacturing of gas would be similar to generating electricity
16 than transporting an end-product should be rejected. PPL Electric has not sold
17 *any of the facilities at a profit, consequently, Mr. Prisco's statement that some of*
18 *these properties may have been sold at a profit and the profit be used to mitigate*
19 *the cost of remediation is moot. For the reasons stated above, Mr. McCormick's*
20 *statement that the costs related to remediation at manufactured gas plants may*
21 *be generation-related costs improperly included in the proposed distribution rates*
22 *should be rejected. Furthermore, Mr. Epstein questioned the future cost estimate*
23 *that, in his opinion, was based upon a single site and was beyond what was*
24 *necessary for the final phase of PCB cleanup. The single site Mr. Epstein was*
25 *likely referring to in his statement was the former Sunbury Manufactured Gas*
26 *Plant (MGP) site, which is not a PCB site. PPL Electric used the level of Sunbury*
27 *MGP site costs, along with its past experience at other MGP sites, as its basis for*

1 the proposed future annual remediation costs that it may incur to address the
2 other 18 former MGP sites as discussed in PPL Electric's response to Question
3 OTS-RE-149 of Interrogatories of the Office of Trial Staff, Set 20, dated
4 June 8, 2004. Although the Company continues to believe that its claim is
5 reasonable, it is difficult to project annual remediation costs with certainty. As a
6 result, PPL Electric can accept the proposal of Mr. Morgan to use a three-year
7 average to derive a reasonable amount for environmental remediation expense.
8 The average expenditures for 2001-2003 for environmental remediation, as set
9 forth on Schedule LKM-12 prepared by Mr. Morgan, are \$1,073,000. PPL Electric
10 agrees to reduce its claim by \$2,483,000 for environmental remediation expense
11 to \$1,073,000.
12

13 X. Late Payment Revenue

14 Q. Have you reviewed Mr. Gruber's testimony regarding late payment revenue?

15 A. Yes, I have. Mr. Gruber recommends an increase in late payment revenue,
16 which would lower the Company's revenue requirement. In Mr. Gruber's
17 testimony, he states that the Company should not have rounded its five-year
18 average late payment revenue calculation from \$6,336,000 to the claimed
19 amount of \$6,000,000. Additionally, Mr. Gruber also states that the Company's
20 five-year estimation methodology is not appropriate in calculating the rate case
21 claim for late payment revenues. Mr. Gruber proposes using a three-year
22 historical average of the percentage of overall revenue represented by late
23 payment revenue, which would increase late payment pro forma revenue at
24 present rates to \$7,090,000.

25 Q. Do you agree with Mr. Gruber's proposal?

26 A. No. The Company believes that using a five-year average of late payment
27 revenue is appropriate and the methodology is consistent with rate case claims in

1 previous Company proceedings approved by the PUC. By using the actual late
2 payment fee dollars over the last five years, instead of a percentage of late
3 payment fee revenue over the total revenues, the Company has more accurately
4 estimated the actual dollars forecast for the 2004 test year. The Company's use
5 of an average of the actual billed dollars eliminates any material swings in billed
6 revenues from year-to-year. However, the Company does agree with Mr. Gruber
7 that rounding the average amount from \$6,336,000 to \$6,000,000 was not
8 appropriate and believes that the rate case claim for late payment fees should be
9 adjusted to the five-year average calculated amount of \$6,336,000.

11 XI. Injuries and Damages

12 Q. Please describe the adjustments for Injuries and Damages proposed Mr. Prisco.

13 A. Mr. Prisco's testimony recommends the claim for injuries and damages be
14 reduced by \$368,000 and refers to DOD Exhibit TJP-7. DOD Exhibit TJP-7 sets
15 forth the adjustment as \$348,000.

16
17 Q. What is the basis of the proposed adjustment?

18 A. Mr. Prisco believes that it is more appropriate to base the claim on the historical
19 amount for 2003 (\$1,169,000) and not on speculation, and states that the
20 Company will have fewer employees, which should reduce the cost from the
21 previous year.

22
23 Q. Do you agree with the proposed adjustment?

24 A. No, I do not agree. First, for the reasons referenced earlier in my testimony, the
25 Company does not believe it is appropriate to select and normalize the claim for
26 individual FERC accounts. Second, Mr. Prisco ignores the actual cost for 2001
27 and 2002 which were \$1,374,198 and \$1,325,470, respectively, and focuses on

1 the 2003 amount, which was abnormally low. Accordingly, the proposed
2 adjustment should be rejected.

3
4 **XII. Self-Funded Health Insurance**

5 Q. Please describe the adjustments for self-funded health insurance proposed by
6 Mr. Prisco.

7 A. Mr. Prisco's testimony states that the self-funded insurance programs have been
8 accumulating a large reserve over the past few years and recommends that
9 \$3,000,000 of the \$3,573,000 liability balance should be returned to ratepayers
10 and amortized over a three-year period, reducing the claim by \$1,000,000, as set
11 forth in DOD/FEA Exhibit TJP-8.

12
13 Q. Do you agree with the proposed adjustment?

14 A. No, I do not agree. Mr. Prisco is incorrect in his belief that the liability balance is
15 too large. The liability balance at the end of 2003 also is \$3,573,000. As a result
16 of the normal processing of medical claims, there is a delay or lag in the timing
17 from when an employee receives medical care under an employer-sponsored
18 plan, to the time the costs for those services are submitted by the health care
19 provider to the insurance carrier, and ultimately to the employer for payment.
20 Generally accepted accounting principles in the United States require the accrual
21 of this estimated delay/lag, which is referred to as a medical claims Incurred But
22 Not Reported (IBNR) liability. Standard practice is to reserve for between 60 and
23 90 days of claims lag. PPL Electric's medical liability of \$3,573,000 includes an
24 IBNR reserve of \$2.9 million based on a conservative 60-day assumed claims
25 lag. The remaining amount of approximately \$673,000 represents known 2003
26 claims paid in 2004.

1 More importantly, the \$3.6 million identified by Mr. Prisco is not even part of
2 the Company's claim for health insurance. The claim for self-funded health
3 insurance programs is \$18,838,000 which does not include the \$3.6 million
4 referenced by Mr. Prisco. Actual claims charged against the liability were
5 \$16,968,800 in 2003, \$19,540,000 in 2002 and \$17,903,200 in 2001 as set forth
6 in the response to Question 31 of Interrogatories of the Office of Consumer
7 Advocate, Set III, dated April 27,2004. The issue is the reasonableness of the
8 claim of \$18,838,000, which is supported by historical experience and the trend
9 in health care inflation.

10 11 **XIII. Executive Compensation**

12 Q. Mr. Epstein stated that PPL Electric should align and incent a portion of
13 executive compensation with "rate payers interest" and that the percent of
14 executive compensation allocated to PPL Electric should be indexed to reliability,
15 community investment, and customer satisfaction. The index, established by the
16 Corporate Governance Committee of the Board of Director's of PPL Corporation
17 and the PUC Law Bureau, would be monitored by the Commission's Bureau of
18 Consumer Services. As these categories increase or decrease, so would the PPL
19 Electric portion of the executives' compensation contributions. The PUC also
20 would be accorded non-voting Board monitor status on the Corporate
21 Governance Committee.

22 Or, as Mr. Epstein stated, PPL Corporation ("PPL") could elect to eliminate
23 corporate bonuses and incentives received from hostage PPL Electric
24 ratepayers.

25 Do you agree with Mr. Epstein's statements?

26 A. No, I do not. In addressing the ideas that a portion of executive compensation
27 allocated to PPL Electric should be based on "ratepayers interest" and indexed

1 based on reliability, community investment, and customer satisfaction, I have
2 several comments. First, only a portion of PPL Corporation's executive
3 compensation is allocated to PPL Electric because PPL Corporation executives
4 oversee the entire corporation, including the delivery, supply, and international
5 segments. Additionally, PPL Electric's allocation percentage has decreased from
6 36.37% in 2002 to 26.49% in 2003 to 26.28% for the 2004 test year.

7 Over the years, PPL Electric has consistently won awards for customer
8 satisfaction and community involvement. In five of the last six years, JD Power
9 and Associates awarded the Company five first place East Region Residential
10 Customer Satisfaction Awards. In four of the last five years of available results,
11 JD Power and Associates awarded the Company four first place East Region
12 Midsize Business Customer Satisfaction Awards. In addition, in the last two
13 years, the American Customer Satisfaction Index (ACSI) rated the combination of
14 PPL Electric and PPL Gas Utilities number one in a customer satisfaction survey
15 of the 30 largest utilities in the nation. These awards certainly show that PPL
16 Electric is highly regarded in customer satisfaction and community involvement
17 and that executive salaries currently are appropriate based on the criteria
18 suggested by Mr. Epstein.

19 In addressing Mr. Epstein's alternative of having PPL elect to eliminate
20 corporate bonuses and incentives received from hostage PPL Electric
21 ratepayers, I disagree. Incentives are a strong tool used to motivate executives
22 and maintain corporate talent and expertise. To eliminate such incentives could
23 cause a general decline in productivity and the Company may risk losing key
24 executives on its management team.

25
26 Q. Mr. Schadt, are you proposing any other adjustments than those previously
27 mentioned?

1 A. Yes. I am also proposing an adjustment to the amortization of the Hurricane
2 Isabel regulatory asset. This adjustment is based on a change in the regulatory
3 asset balance as of 6/30/2004. The changes are a refinement to PPL's cost to
4 restore service to customers after the storm. The total change to the regulatory
5 asset was \$136,000, which decreases the annual amortization by \$27,000.

6
7 Q. Mr. Schadt, are there any documents that summarize PPL Electric's witnesses'
8 proposed adjustments and the impact to PPL Electric's rate request?

9 A. Yes. PPL Electric is filing Exhibit Future 1 (Revised), that reflects the changes
10 described in this testimony and the testimonies of Mr. Kleha and Mr. Krall.

11
12 Q. Does that conclude your rebuttal testimony?

13 A. Yes.



**TOWERS
PERRIN**

HR SERVICES

June 21, 2004

Mr. Don Sparaco
Director, Compensation & Benefits
PPL Corporation
2 North 9th Street
Allentown, PA 18101-1139

Mr. T. W. Hatten
Director of Investments and Pensions
PPL Corporation
2 North 9th Street
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Dear Don and Sunny:

**PPL POSTRETIREMENT MEDICAL PROGRAM
2004 FAS 106 RESULTS**

The purpose of this letter is to review the following:

- Our understanding of the underlying methodology used to develop retiree medical contributions for retirees at PPL Corporation
- 2004 FAS 106 results, before reflecting the effects of Medicare Part D
- A preliminary discussion of 2004 accounting options that PPL can consider for reflecting the effects of Medicare Part D

PPL RETIREE COST SHARING

During 2002 to 2003, PPL and Towers Perrin discussed PPL's practice for developing retiree contributions in comparison to the assumed methodology in the FAS 106 valuation. The result of these conversations was that retiree contributions effective as of 7/1/2003 used an average of the previous two years' actual cost (claims plus expenses divided by adult plan participants) compared to the current year's DDB cap (the "two-year average" methodology). This methodology was reflected in the final 2003 FAS 106 results.

PPL, seeking to adopt a current year cap approach starting in 2004, opted to use a four-year transition approach for all retirees (union and management) to gradually reduce the "hidden subsidy" under the two-year average methodology. The methodology that PPL intended to use on a going forward basis was to use the prior year's actual cost projected with trend to the contribution period compared to the current year's DDB cap (the "projected" methodology). The hidden subsidy is, therefore, the difference between

the two years of lagging health care costs and the trended health care costs; this hidden subsidy was projected to be eliminated by the 7/1/2007 to 7/1/2008 contribution year.

Late in 2003, PPL released a letter to retirees and employees in order to communicate this projected method of developing retiree contributions. With this retiree communication, this methodology was considered to be the substantive plan effective for the 2004 FAS 106 valuation.

During 2004, an inquiry was made by a union representative challenging the new methodology. PPL researched the labor negotiation history and found an agreement from 1991, the time of retiree cap inception, stating the methodology the company would use in determining union retiree contributions.

For 2004, therefore, the revised substantive plan is as follows:

- For management retirees, the projected methodology with the four-year transition will continue. Retiree contributions will be determined on a calendar year basis going forward instead of each July 1. These costs will be based on non-union experience only.
- For union retirees, the retiree contributions will be determined on July 1 each year based on the excess of the prior calendar year's actual costs (claims plus expenses divided by adult plan participants) over the DDB cap. The costs will be based on experience from both union and non-union retirees.

2004 FAS 106 RESULTS (PRIOR TO REFLECTING MEDICARE PART D)

The following chart illustrates the change in 2004 FAS 106 obligations and expense for the current substantive plan. A detailed exhibit is enclosed as an attachment. Please note that these results do not reflect any effects from Medicare Part D.

Scenario (\$ millions)	APBO	Service Cost	FAS 106 Expense	Change
Two-year Average Methodology	\$499	\$6.7	\$47	—
Projected Methodology (applied to all capped retirees, previously communicated)	\$415	\$5.0	\$28	(\$19)
2004 Substantive Plan	\$451	\$5.7	\$36	\$8

2004 FAS 106 RESULTS (ACCOUNTING OPTIONS TO REFLECT MEDICARE PART D)

As we have discussed, on May 19 FASB issued the final FSP 106-2 to provide guidance on accounting for the financial effects of the 2003 Medicare Modernization Act (FSP 106-1 is superseded upon adoption of FSP 106-2). The FSP offers options for employers to consider in reflecting the effects for Medicare Part D in 2004. These options include:

- Reflecting the plan's eligibility for the federal subsidy. The FSP presumes that actuarial equivalence will be based on the employer's share of the cost (total cost less employee contributions). The FSP allows actuarial equivalence to be assessed for accounting purposes by groups of plan participants, rather than for the plan as a whole. In PPL's case, we believe that it is likely that retirees prior to 4/1/1993 (uncapped retirees) will be eligible for the subsidy long term, while capped retirees may only be eligible for a certain number of years.
- Changes in assumed participation rates, per capita claims cost and health care trend rates for 2006 and beyond.

This FSP is effective for fiscal quarters beginning after June 15, 2004 and employers may adopt retroactively or prospectively.

In terms of accounting for the Act, PPL has four options:

	Adopt Retroactively	Adopt Prospectively
Adopt 2nd Quarter 2004	<ul style="list-style-type: none"> ■ Restate 1st quarter earnings ■ Discount rate of 6.25% 	<ul style="list-style-type: none"> ■ Three quarters of recognition in 2004 ■ Moody's AA yield on March 31, 2004 was 5.75%, suggesting a discount rate of 5.75% or 6.00%
Adopt 3rd Quarter 2004	<ul style="list-style-type: none"> ■ Restate 1st and 2nd quarter earnings ■ Discount rate of 6.25% 	<ul style="list-style-type: none"> ■ Two quarters of recognition in 2004 ■ Moody's AA yield as of close of business on June 18, 2004 was 6.16%, suggesting a discount rate of 6.25%

It is our understanding that PPL will most likely adopt FSP 106-2 effective with the 3rd quarter.

Mr. Don Sparaco
Mr. T. W. Hatten
June 21, 2004
Page 4.


**TOWERS
PERRIN**
HR SERVICES

The following chart illustrates the impact on 2004 FAS 106 results for the whole year assuming that the federal subsidy only applies to uncapped retirees, with no other changes in assumptions.

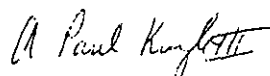
\$ millions	APBO	Service Cost	FAS 106 Expense	Change
2004 Final Results (based on revised substantive plan)	\$451	\$5.7	\$36	--
2004 Results (reflecting effects from Medicare Part D)	\$445	\$5.7	\$35	(\$1)

We plan to discuss PPL's options and decision points in more detail during our meeting on July 12th. We anticipate providing some additional options at that time.

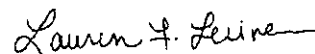
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Don and Sunny, we hope that you find this information useful. We would like to schedule a conference call with you once you have had a chance to review this information. In the meantime, please call us with any questions.

Sincerely,



A. Paul Kienzle III, FSA
Principal
Direct Dial: 215-246-7390



Lauren F. Levine, FSA
Consultant
Direct Dial: 215-246-7869

Attachment

cc: Tom Croyle, PPL Corporation
Susan Paule, PPL Corporation
George Sunder, PPL Corporation
Royce Kosoff, Towers Perrin

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DOCKETED
AUG 25 2004

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

RECEIVED

AUG 24 2004

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU
PPL ELECTRIC UTILITIES CORPORATION

Statement No. 3-R

Rebuttal Testimony of David R. Woodruff

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

2 A. David R. Woodruff, Manager – Load Analysis for PPL Electric Utilities,
3 Two North Ninth Street, Allentown, Pennsylvania, 18101.

4

5 Q. Mr. Woodruff, have you testified previously in this proceeding?

6 A. Yes, I submitted direct testimony, Statement 3, on March 29, 2004.

7

8 Q. What is the purpose of your rebuttal testimony?

9 A. I will respond to the direct testimony of Mr. Kubas of the Office of Trail
10 Staff, in which he concluded that "present rate revenue for the residential
11 heating rate schedule be increased by \$15,109,000."

12

13 Q. Please summarize your rebuttal testimony.

14 A. Mr. Kubas has made several errors and inappropriate assumptions in his
15 analysis. Specifically, his analysis over-estimates the weather impact on
16 sales to electric heat customers. Further, I will show that PPL Electric's
17 forecast of sales to electric heat customers for the 2004 future test year
18 has been accurate year-to-date.

19

20 **2004 Sales Forecast**

21

22 Q. What errors are contained in Mr. Kubas' analysis?

23 A. Mr. Kubas makes several errors in his analysis:

- 1 • In OTS Exhibit No. 3, Schedule 2, Page 2 of 2, Mr. Kubas shows
2 the Heating Degree Days (HDDs) for December 2002. Exhibit
3 DRW-2, Page 1 of 2, Table 1 shows that the average of the Wilkes-
4 Barre/Scranton, Allentown, Harrisburg/Middletown, and
5 Williamsport weather stations using this data is 1,095 HDDs.
6 However, OTS Exhibit No. 3, Schedule 6, is used to calculate the
7 average HDDs that are used in Mr. Kubas' analysis. This schedule
8 lists the average HDDs for these 4 weather stations, and shows the
9 December 2002 average as 812 HDDs. In the calculation of the
10 total HDDs on Schedule 6 for all months, Mr. Kubas incorrectly
11 included only 3 weather stations (he neglected to include the
12 Williamsport value in the total shown in Column F), but calculated
13 the average in Column G by dividing the total by 4. This calculation
14 by Mr. Kubas is shown in Exhibit DRW-2, Page 1 of 2, Table 1.
15 This error resulted in a substantial under-calculation of the HDDs
16 used to calculate the Normalized Load shown in OTS Exhibit No. 3,
17 Schedule 7 (812 HDDs vs 1095 HDDs). This error accounts for
18 90% of the increase proposed by Mr. Kubas in the present rate
19 revenue for the residential heating rate schedule.
- 20 • In calculating actual HDDs, Mr. Kubas also makes an error in
21 calculating the normal HDDs. He used the NOAA data in OTS
22 Exhibit No. 3 to calculate the Normal HDDs. Harrisburg/Capital
23 City station data was used in this calculation. However, in

1 calculating the actual HDDs on Schedule 6, the
2 Harrisburg/Middletown station data was used. PPL Electric uses
3 Harrisburg/Middletown station in all its calculations.

- 4 • The actual sales figures used by Mr. Kubas in OTS Exhibit No. 3,
5 Schedule 7 for June and July 2002 are incorrect. PPL Electric
6 provided the actual values in its response to OTS Interrogatory
7 OTS-RE-8.
- 8 • In OTS Exhibit No. 3, Schedule 5, Page 1 of 3, the bills breakdown
9 allocates Rate Schedule RTS and Rate Schedule RTD customers
10 to both heating and non-heating. All of the Rate Schedule RTS and
11 Rate Schedule RTD customers are electric heat customers.

12
13 Q. What inappropriate assumptions does Mr. Kubas employ?

14 A. The forecast PPL Electric produces is a forecast of revenue-month sales.
15 In OTS Exhibit No. 3, Schedule 7, Mr. Kubas attempts to normalize
16 revenue-month sales using calendar-month weather data. Any
17 comparison of monthly sales and weather must be done on the same
18 basis. Bills are rendered to customers throughout the month and,
19 therefore, revenue-month sales will not directly correspond to calendar-
20 month HDDs and Cooling Degree Days (CDDs). For example, if one
21 makes the simplifying assumption that customers are billed the same time
22 every month, then a customer who is billed on the 15th day of each month
23 will have half of his usage in the current month and half of his usage in the

1 prior month. In order to make a comparison of revenue-month sales and
2 weather, the weather data must be adjusted to show the HDDs applicable
3 to the usage in the current month, and the HDDs applicable to the usage
4 in the prior month. In reality, customer meter reads are not the same time
5 every month, and the number of billing days will vary. The HDDs and
6 CDDs for all 20 billing controls must be calculated on a daily basis in order
7 to place the sales and weather data on the same revenue-month basis.
8 As explained in the response to OTS Interrogatory OTS-RE-6, the
9 revenue-month values are calculated in PPL Electric's forecast model
10 based on meter reading schedules.

11 Prior to 1985, PPL Electric had used calendar-month HDDs and
12 CDDs. PPL Electric recognized this inherent weakness in using calendar-
13 month HDDs and CDDs and began using revenue-month HDDs and
14 CDDs, based on daily degree days.

15 Mr. Kubas' analysis also ignores the impact of the summer cooling
16 season on annual normalized sales. A large number of electric heat
17 customers also have electric air conditioning. Mr. Kubas uses the actual
18 sales from June 2002 through September 2002 in his calculation of
19 normalized load. Because the summer of 2002 was hotter than normal,
20 the normalized load would be less than actual for the cooling season.
21 This would further reduce the total annual normalized load.

22
23 Q. Do you agree with Mr. Kubas' explanation of customers' Base Load?

1 A. No. Mr. Kubas makes the assumption that all usage above an October
2 Base Load is due to weather. This results in Mr. Kubas overstating the
3 impact of weather. In reality, usage will vary month-by-month due to other
4 variables. Lighting requirements are higher during the winter due to the
5 reduced hours of daylight. Holiday lighting adds additional load
6 requirements. During the summer, Base Load requirements will be
7 reduced due to reduced lighting needs, more outdoor activities, and
8 vacations. For these reasons, PPL Electric's forecast model includes
9 monthly and lighting variables to account for these differences in usage
10 throughout the year.

11 Finally, Mr. Kubas includes May as a heating month, when the
12 actual and normal HDDs are lower than his Base Load month of October.
13 May is not considered to be part of the heating season, and should have
14 been excluded from this analysis.

15
16 Q. You also mentioned the forecast model used by the Company to forecast
17 sales. Mr. Kubas says you refused to provide a working copy. Is this
18 true?

19 A. As explained in the response to OTS Interrogatory OTS-RE-7, the request
20 for the model was for an Excel version. PPL Electric's sales forecast
21 model is not in an Excel format, rather it is in a proprietary software
22 program, Metrix ND, developed by RER, Inc. I do not know if OTS has a
23 license for this and other software products (such as SQL Server) required

1 to run the model. The sales forecast model also is installed on a server,
2 and requires access to PPL Electric's network in order to operate. For
3 these reasons, PPL Electric could not provide the model to the OTS. And,
4 in any event, as I explained in OTS Interrogatory OTS-RE-6, 30-year data
5 is not available on a revenue-month basis. So, even if we had provided
6 the model and access to the server, OTS would not have been able to use
7 it to make a 30-year calculation.

8
9 Q. Mr. Kubas states that several inputs and assumptions in the model are
10 incorrect. Is this true?

11 A. No. Mr. Kubas states that PPL Electric's weather data is not official NOAA
12 data. PPL Electric obtains the weather data from Meteorlogix.
13 Meteorlogix obtains its weather data from the weather monitoring
14 equipment at the respective airports. This equipment is installed and
15 maintained by either NOAA or the FAA. The hourly weather data from
16 each airport is sent to a NOAA facility in the Washington, DC / Maryland
17 area. Meteorlogix receives the hourly weather data via a direct line from
18 this facility. PPL Electric receives its hourly data from Meteorlogix via a
19 File Transfer Protocol site on a daily basis. This file contains hourly
20 observations from midnight to midnight for the prior day. These weather
21 files that PPL Electric receives from Meteorlogix contain clean data that
22 excludes any erroneous observations and includes estimates of any

1 missing values. This data is reviewed by the meteorologists at
2 Meteorlogix.

3 Mr. Kubas made a second point about the long-standing policy of
4 using 30 years of data to determine "normal" weather and HDDs. As
5 stated in the response to OTS Interrogatory OTS-RE-6, PPL Electric uses
6 a 20-year rolling average because the meter reading schedules prior to
7 1980 are not available. These schedules are required to develop the
8 revenue-month HDDs and CDDs.

9 Also, PJM has established a standard summer peak demand
10 process that incorporates a 20-year rolling average weather parameter
11 (PJM Manual 19: Load Data Systems, Section 4). PPL Electric also
12 provides PJM with monthly sales forecasts. In order to be consistent with
13 the PJM requirements, PPL Electric elected to use a 20-year rolling
14 average in its process of obtaining sales on a normal-weather basis.

15
16 Q. How does Mr. Kubas' estimate of residential heating sales for the future
17 test year compare to PPL Electric's forecast when compared to 2003
18 actual and weather-normalized sales?

19 A. Mr. Kubas estimated normalized usage for the future test year as
20 7,132,142,893 kWh (OTS Exhibit No. 3, Schedule 7, Column J, Line 14).
21 PPL Electric provided actual and normalized residential heating sales in
22 Attachment 1 of the response to OTS Interrogatory OTS-RE-33. Mr.
23 Kubas' value of 7,132,142,893 kWh would result in an increase over 2003

1 actual sales to residential heating customers of 10.4%, and 12.7% over
2 2003 normalized sales.

3 PPL Electric's forecast of residential heating sales, however, is for
4 a more modest growth of 1.6% over 2003 actual and 3.7% over 2003
5 normalized, as shown in Exhibit DRW-2, Page 2 of 2, Table 2.

6
7 Q. The future test year is now half over. How has PPL Electric's forecast of
8 sales for residential heating customers compared to actual and weather-
9 normalized sales?

10 A. Exhibit DRW-2, Page 2 of 2, Table 3 compares electric heat sales to
11 forecast. For the first half of 2004, sales to PPL Electric's electric heat
12 customers is 0.5% above forecast. On a weather-normalized basis, actual
13 sales are 1.8% below forecast.

14
15 Q. Does this conclude your testimony?

16 A. Yes it does.

PPL ELECTRIC UTILITIES CORPORATION

Exhibit DRW-2

**Table 1: Calculation of Heating Degree Days Based on
Published NOAA Data – Comparison of PPL Electric's
Calculation vs. OTS's Calculation**

**Table 2: Comparison of PPL Electric's Forecast vs. OTS's
Forecast – 2003 to 2004 Growth**

**Table 3: Electric heat Customers – Comparison of Forecast vs.
Actual Sales**

Witness: David R. Woodruff

Table 1
Calculation of Heating Degree Days Based on Published NOAA Data
Comparison of PPL Electric's Calculation vs. OTS's Calculation
December 2002

(A)	(B)	(C)	(D)	(E)	(F) (B+C+D+E)	(G) (F / 4)
PPL Electric						
	Allentown	Harrisburg	Scranton	Williamsport	Total	Average
December 2002	1091	1047	1110	1130	4378	1095
OTS						
	Allentown	Harrisburg	Scranton	Williamsport	Total	Average
December 2002	1091	1047	1110	*	3248	812 **

* Shown on OTS Exhibit No. 3, schedule 6 but omitted in calculation of Total.

** Average in OTS calculation is Total of 3 weather stations divided by 4.

Table 2
Comparison of PPL Electric's Forecast vs. OTS's Forecast
2003 to 2004 Growth
(MWh)

	A	B	C	D	E	F
	2003	2004	(B - A) / A	2003	(A + D)	(B - E) / E
Forecast	Actual	Forecasted	% Growth	Weather Adjustment ¹	Weather-normalized Actual	% Growth
PPL Electric	6,460,237	6,563,165	1.6%	(131,767)	6,328,470	3.7%
OTS	6,460,237	7,132,143	10.4%	(131,767)	6,328,470	12.7%

Table 3
Electric Heat Customers
Comparison of Forecast vs. Actual Sales
(MWh)

Monthly							
	A	B	C	D	E	F	
	2004	Forecast	Actual	(B - A) / A	Weather Adjustment	(B + D)	(E - A) / A
				% Variance		Weather-normalized Actual	% Fcst Error
1	879,522	847,503	-3.6%	(7,971)	839,532	-4.5%	
2	835,129	912,067	9.2%	(94,940)	817,127	-2.2%	
3	746,854	721,059	-3.5%	11,191	732,250	-2.0%	
4	578,551	568,846	-1.7%	(6,429)	562,417	-2.8%	
5	399,049	395,038	-1.0%	12,481	407,519	2.1%	
6	344,438	357,536	3.8%	(559)	356,977	3.6%	
7	388,299						
8	397,609						
9	356,473						
10	382,501						
11	530,071						
12	724,669						
Cumulative YTD							
	A	B	C	D	E	F	
	2004	Forecast	Actual	(B - A) / A	Weather Adjustment	(B + D)	(E - A) / A
				% Variance		Weather-normalized Actual	% Fcst Error
1	879,522	847,503	-3.6%	(7,971)	839,532	-4.5%	
2	1,714,651	1,759,570	2.6%	(102,911)	1,656,659	-3.4%	
3	2,461,505	2,480,629	0.8%	(91,720)	2,388,909	-2.9%	
4	3,040,056	3,049,475	0.3%	(98,149)	2,951,326	-2.9%	
5	3,439,105	3,444,514	0.2%	(85,668)	3,358,846	-2.3%	
6	3,783,543	3,802,050	0.5%	(86,227)	3,715,823	-1.8%	

Notes:

¹ PPL Electric's Weather Adjustment used to adjust actual for both comparisons.

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AUG 4 2004

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

DOCKETED
AUG 25 2004

PPL Electric Utilities Corporation

Statement No. 4-R

Rebuttal Testimony of Douglas A. Krall

1 Q. Please state your full name and business address.

2 A. My name is Douglas A. Krall. My business address is Two North Ninth Street,
3 Allentown, Pennsylvania, 18101.

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

5 A. I am employed by PPL Electric Utilities Corporation ("PPL Electric" or the
6 "Company") a subsidiary of PPL Corporation. I work in the Asset Management
7 Department of PPL Electric and my title is Manager – Regulatory Strategy.

8 Q. Have you provided testimony previously in this proceeding?

9 A. Yes, I have. I provided written direct testimony that was designated as
10 Statement No. 4. I also provided Exhibit DAK1.

11 Q. Please describe the purpose of your rebuttal testimony.

12 A. The purpose of my rebuttal testimony is to address issues raised by other parties
13 regarding the following:

- 14 • The inclusion of plant held for future use in base rates.
- 15 • PPL Electric's proposal to establish a Distribution System Improvement
16 Charge ("DSIC").
- 17 • Issues related to PPL Electric's proposed Transmission Service Charge
18 ("TSC").
- 19 • PPL Electric's proposed allocation of distribution revenue requirements.
- 20 • PPL Electric's request to amortize and recover from customers costs
21 associated with Hurricane Isabel.
- 22 • Costs and benefits associated with the Automated Meter Reading ("AMR")
23 system.

- Proposals offered by Strategic Energy to promote retail competition.

Q. Are you sponsoring additional exhibits as part of your rebuttal testimony?

A. Yes, I am. Exhibits DAK2, DAK3 and DAK4 are attached.

Plant Held for Future Use

Q. Please describe PPL Electric's request in this proceeding for plant held for future use.

A. In my direct testimony, I stated that PPL Electric is making a claim to include in rate base \$2,212,678 related to distribution plant held for future use. I further stated that if this claim is not approved by the Commission, PPL Electric, in the alternative, is requesting approval to accrue a return equivalent to the applicable AFUDC rate on these investments and to include the accrued amount as part of its distribution plant in-service at the time such plant is placed into service.

Q. OCA witness Lafayette Morgan has recommended that the Commission accept PPL Electric's alternative request and allow the Company to accrue AFUDC on those specific parcels of land subject to normal regulatory oversight at the time the Company requests such plant be placed into service. Does the Company accept this proposal?

A. Yes, the Company does. An appropriate adjustment to rate base is reflected in Revised Exhibit Future 1.

Distribution System Improvement Charge

Q. Please describe PPL Electric's proposal to establish a DSIC.

A. The DSIC that PPL Electric has proposed is a rate mechanism that would allow the Company to recover, between formal rate cases, the carrying costs on

1 certain capital investments in distribution facilities. In the absence of DSIC, PPL
2 Electric can not collect any money from customers to support these investments
3 in facilities until they are recognized as additions to rate base in the context of a
4 formal rate proceeding. This situation can go on for years and is becoming
5 increasingly critical as distribution facilities built in the high growth 1960s, 1970s,
6 and 1980s are nearing the end of their useful lives. The DSIC will enable PPL
7 Electric to begin collecting money to cover the carrying costs of these facilities
8 shortly after the facilities are completed and begin providing service to
9 customers. As a result, PPL Electric will be better able to finance the
10 construction of facilities that are required to maintain safe and reliable service
11 without the immediate need to file a formal base rate case.

12 Q. Please describe the issues raised by other parties relative to this proposal.

13 A. OCA witness Thomas Catlin and OTS witness Michael Gruber argue that PPL
14 Electric's proposed DSIC is illegal under the Pennsylvania Public Utility Code
15 and represents improper single-issue rate-making. PPLICA witness Stephen
16 Baron, DOD witness Thomas Prisco, and OSBA witnesses Robert Knecht and
17 Mark Ewen echo the criticism that DSIC represents improper single-issue rate-
18 making. OCA witness Catlin and OSBA witnesses Knecht and Ewen also argue
19 that verification is problematic. OTS witness Gruber also questions the inclusion
20 of substation equipment and security improvements as DSIC-eligible property.
21 PPLICA witness Baron also questions the need for DSIC and, along with DOD
22 witness Kenneth Kincel and OSBA witnesses Knecht and Ewen, the
23 appropriateness of a kWh-based recovery mechanism. OSBA witnesses Knecht

1 and Ewen also question the necessity for DSIC. Witness Eric Epstein argues
2 that DSIC is illegal, discriminatory, and should not address security
3 improvements.

4 Q. How do you respond to the argument that DSIC constitutes improper single-issue
5 rate-making?

6 A. That argument is not correct. Although PPL Electric will respond fully to such
7 legal arguments in its briefs, counsel has provided me with a brief overview of
8 PPL Electric's position on the legality of its proposed DSIC.

9 The contentions of other parties, that the DSIC is unlawful, ignore the fact
10 that Section 1307(a) of the Public Utility Code, 66 Pa.C.S. § 1307(a), expressly
11 authorizes automatic adjustment clauses, subject to the Commission's approval.

12 The parties who contend that single issue ratemaking is unlawful are incorrectly
13 reading Section 1307(a) out of existence. Of course, PPL Electric must
14 demonstrate to the Commission that the proposed DSIC is in the public interest,
15 but there is no blanket rule that automatic adjustment clauses governing recovery
16 of an expense or class of expenses are unlawful.

17 Q. Certain parties contend that PPL Electric's proposed DSIC is not proper because
18 there is no specific authority for it similar to Section 1307(g) which authorizes
19 DSICs for water utilities. Do you agree with those comments?

20 A. No, I do not. PPL Electric will explain fully in its briefs why the absence of a
21 specific authorization for its proposed DSIC, such as Section 1307(g) for water
22 utilities, does not preclude the Commission from approving PPL Electric's DSIC.

23 I note, however, that the Commission approved a DSIC for a water utility before

1 Section 1307(g) of the Public Utility Code was enacted. Section 1307(g) was
2 enacted into law under the Act of December 18, 1996, P.L. 1061, No. 156, § 1,
3 effective on February 16, 1997. Previously, in an Order entered on August 26,
4 1996, the Commission approved a form of DSIC in *Re: Pennsylvania-American*
5 *Water Company*, Docket No. P-00961031, 86 Pa. PUC 415 (1996). The
6 Commission obviously concluded that a specific statutory authorization to create
7 a DSIC for water utilities was not required and concluded also that DSICs meet
8 the requirements of Section 1307(a) of the Public Utility Code.

9 Further, since the enactment of Section 1307(g), the Commission has
10 approved a similar tariff provision, a Collection System Improvement Charge
11 ("CSIC"), for a wastewater company despite the absence of any specific statutory
12 authorization for such an automatic adjustment clause.

13 Specifically, the CSIC for Pennsylvania-American Water Company's
14 sewer divisions was implemented pursuant to the Commission's approval in *Pa.*
15 *P.U.C. v. Pennsylvania-American Water Co.*, Docket No. R-00027982
16 (November 9, 2003). There, the Commission approved the CSIC despite the
17 facts that wastewater or sewer utilities are not mentioned in Section 1307(g) and
18 that there is no other statutory provision specifically authorizing a CSIC for sewer
19 or wastewater utilities. I should note that the OCA has appealed the
20 Commission's approval of the CSIC. The appeal is presently pending before the
21 Pennsylvania Commonwealth Court at Docket No. 2497 C.D. 2003.

22 Q. How do you respond the criticism that verification of DSIC will be problematic?

1 A. PPL Electric knows of no reason why an electric DSIC should be more difficult to
2 administer and verify than a water DSIC or a sewer utility CSIC.

3 Initially, I note that water and sewer companies are subject to the same
4 alleged "incentives" to classify as many property additions as possible as being
5 subject to the DSIC or CSIC. Nevertheless, the water and sewer companies and
6 the Commission have not experienced, to my knowledge, substantial controversy
7 with regard to these matters. It is my understanding that the Commission's
8 Bureau of Audits periodically reviews the plant additions of water utilities that are
9 reflected in the water utilities' DSICs and that there has not been substantial
10 controversy with regard to these matters.

11 Further, PPL Electric's proposed DSIC explicitly specifies the categories of
12 property that are eligible for the DSIC as follows:

- 13 • Poles (Account 364) oil circuit reclosures (Account 365), underground
14 cable (Account 367) and underground services (Account 369) installed as
15 in kind replacements,
- 16 • Area supply substation equipment (Account 362) replacements due to
17 deterioration, failure, or obsolescence to maintain reliability,
- 18 • Unreimbursed costs related to capital projects that relocate Company
19 facilities due to highway relocation work,
- 20 • Distribution line circuit capital replacements to maintain reliability, and
21 security improvements.

22 By tying the eligibility of most plant additions to specific distribution plant
23 accounts, PPL Electric has minimized its discretion with regard to eligibility for

1 the DSIC because these accounts are clear and well-defined under the Uniform
2 System of Accounts.

3 Q. Are there any problems with including security improvements in the DSIC eligible
4 property?

5 A. No, there are not. OTS witness Gruber and Witness Epstein take exception to
6 the Company's proposal to include security improvements under the definition of
7 DSIC-eligible property. Both argue that security improvements are more likely to
8 involve the transmission system, and the Company does not disagree. In such a
9 circumstance, however, costs related to security for transmission facilities would
10 be included in the PJM Open Access Transmission Tariff (OATT) and collected
11 from entities purchasing transmission service from PJM. However, the Company
12 does not preclude the possibility that a governmental authority with appropriate
13 jurisdiction might order security improvements to Company buildings or
14 information systems that are defined as distribution property. The Company
15 believes that recovery of such costs through a DSIC is consistent with the
16 provisions of the Commission's Order regarding "government-imposed
17 requirements." *Re: Pennsylvania-American Water Co.*, 86 Pa. PUC, *supra*, pp.
18 419.

19 Further, as I made clear at page 36 of my direct testimony, PPL Electric
20 Statement No. 4, security improvements would be limited to those recommended
21 by a governmental authority with appropriate jurisdiction. There would be little, if
22 any, discretion for PPL Electric with regard to security investments because the
23 decisions would be made pursuant to governmental recommendations or

1 requirements. For this reason, there should be minimal controversy with regard
2 to the eligibility of specific property additions for the DSIC.

3 Q. How do you respond to the assertion that substation equipment improvements
4 should not be DSIC-eligible property?

5 A. OTS witness Gruber asserts that electric substation equipment is analogous to
6 water pumping stations and, in reliance on a Commission Order in *Petition of the*
7 *Columbia Water Company for Approval to Implement a Tariff through*
8 *Supplement Establishing a Distribution Improvement Charge*, Docket No.
9 P-00021979 (April 17, 2003) ("*Columbia*"), recommends that substation
10 equipment not be eligible for recovery under DSIC. The Company initially
11 responds that, regardless of whether water pumping stations are an appropriate
12 analogy for electrical substations, the Commission's order in the cited case is not
13 relevant because it addresses the proposed construction of a new water pumping
14 station whereas the Company's proposal is for the recovery of costs related to
15 the replacement of existing, deteriorated or failed substation equipment and not
16 the installation of new substations. Indeed, the Company's proposal is consistent
17 with the Commission's *Columbia* Order which states that the intent of DSIC "is to
18 allow cost recovery for distribution system improvement projects requiring
19 immediate implementation due to risk imposed by aging infrastructure or to
20 government-imposed requirements." (*Columbia* Order, p. 14)

21 Furthermore, with regard to the inclusion of the pumping station, the
22 Commission explained at pages 11 – 12 of the *Columbia* Order, the particular
23 pumping station at issue there was an integral part of the facilities for providing

1 emergency water storage and treatment; it was not an integral part of the
2 distribution system. At page 15 of the *Columbia* Order, the Commission
3 explained that this was the basis for its decision that the pumping station be
4 excluded from the DSIC. The Commission did not adopt any rule that pumping
5 stations should never be included in a water utility's DSIC. The decision was
6 instead based upon the unusual circumstances of that particular pumping station.
7 The *Columbia* Order does not support the OTS' proposed exclusion of substation
8 plant additions from PPL Electric's DSIC.

9 Unlike the pumping station at issue in *Columbia*, an electric substation is
10 an integral part of PPL Electric's distribution system. Initially, I note that a small
11 portion of PPL Electric's substations are related to transmission, not distribution,
12 functions. By restricting substation equipment eligible for the DSIC to Account
13 362, however, PPL Electric has restricted DSIC eligible substation additions and
14 replacements to distribution operations and excluded transmission-related
15 substations.

16 As I noted, such substations are an integral part of PPL Electric's
17 distribution system. Electricity is delivered to PPL Electric's distribution system
18 from electric generation stations at high transmission voltages. At substations,
19 voltage levels are reduced to distribution voltage levels so that electricity can be
20 safely provided to the public. Indeed, all electricity distributed by PPL Electric to
21 customers (excluding customers who take service at transmission voltages) flows
22 through substations. The argument that substations are not an integral part of
23 PPL Electric's distribution system is erroneous.

1 Q. Have parties raised other issues with regard to the DSIC?

2 A. Yes, certain parties have indicated that approval of PPL Electric's proposed
3 DSIC would create the possibility that PPL Electric could over achieve its allowed
4 rate of return as a result of other revenue requirement reductions or increases in
5 revenues that are not reflected in the proposed DSIC (OSBA Statement No. 1,
6 p. 5; OCA Statement No. 2, pp. 6-7; DOD Statement of T. Prisco, p. 11; PPLICA
7 Statement No. 1, pp. 46-50; Pa EC Statement No. 1, p. 11). Such concerns are
8 unrealistic. Specifically, I note that, despite the many efficiencies and savings
9 that PPL Electric has implemented since its last base rate case in 1995, PPL
10 Electric's return on equity has continued to erode. In 2003, PPL Electric
11 achieved a return on equity of less than 2 percent. Return on equity is expected
12 to decline to about 1 percent in 2004 (PPL Electric Statement No. 1, p. 3).

13 Added to PPL Electric's history of declining returns on equity is the
14 substantial nature of its construction budget. As set forth in Exhibit DAK-1, PPL
15 Electric plans to spend on average almost \$200 million annually on construction
16 through 2008. Only a small portion of these expenditures would be reflected on
17 the DSIC, but this additional investment in new plant will drive increases in
18 revenue requirements particularly with regard to depreciation, return and income
19 taxes. The combination of the history of PPL Electric's declining returns on
20 equity and its substantial and growing construction budgets suggest strongly that
21 there is no realistic likelihood that PPL Electric will be able to achieve more than
22 its allowed rate of return in the foreseeable future.

1 Further, PPL Electric submits to the Commission quarterly earnings
2 reports pursuant to the requirements of 52 Pa. Code Ch. 71, regarding financial
3 reports. Thus, the Commission has available for its review – four times each
4 year – reports to determine whether PPL Electric is achieving more than its
5 allowed rate of return. Such reports are available to the public. Therefore, any
6 party who believes that PPL Electric is achieving more than its allowed rate of
7 return can raise such matters for review in proceedings before the Commission.

8 Q. Certain parties have objected to PPL Electric's proposed DSIC on the grounds
9 that certain of the plant additions eligible for the DSIC may reduce operation and
10 maintenance expenses (OCA Statement No. 2). Are those concerns justified?

11 A. No, they are not. Initially it must be noted that only a small portion of PPL
12 Electric's plant additions will be eligible for the DSIC. As I explained at page 38
13 of my direct testimony, PPL Electric Statement No. 4, in a typical year, only about
14 \$26 million of plant additions annually would be eligible for the DSIC. This
15 amount should be contrasted with the totality of PPL Electric's construction
16 program which is expected to be about \$200 million per year over the five years
17 ending 2008. Thus, only about 13 percent of PPL Electric's construction and
18 plant additions will be eligible for the DSIC. An investment of this magnitude will
19 not have a substantial effect upon total operation and maintenance expenses.

20 The plant additions eligible for the DSIC will not cause PPL Electric's
21 operation and maintenance expense to be reduced. It must be recalled that,
22 each year, PPL Electric's distribution system is another year older. The small
23 portion of the distribution system that will be replaced by property additions

1 eligible for the DSIC will not materially alter that process. The original cost of
2 PPL Electric's total depreciable plant as of December 31, 2004, is
3 \$4,398,361,788 (Exhibit JJS-1, p. III-5). Thus, DSIC eligible plant additions
4 constitute only about 0.6 percent of PPL Electric's total original cost of plant (\$26
5 million ÷ \$4,398 million). Although it is possible that operation and maintenance
6 expense may be reduced for the particular distribution system component being
7 replaced, there is no reason to believe that PPL Electric's overall operation and
8 maintenance expenses will be reduced as a result of property additions eligible
9 for the DSIC.

10 Q Certain parties have objected to the inclusion of depreciation on qualifying plant
11 additions for recovery under the DSIC on the grounds that existing rates already
12 have a provision for depreciation on the plant being replaced (OSBA Statement
13 No. 1). Are these concerns well-founded?

14 A. No, they are not. Providing for depreciation recovery on qualifying plant
15 additions is necessary to avoid having the Company experience attrition as a
16 result of the qualifying plant addition.

17 On PPL Electric's books, under the Uniform System of Accounts, when old
18 plant is retired and replaced by new plant, the plant balance and the accumulated
19 reserve for depreciation both are adjusted by equal amounts to reflect the
20 retirement of the old plant. Thus, there is no change in net plant as a result of
21 retirement. Similarly, because PPL Electric's depreciation accrual rate applicable
22 to the plant account in which the retired plant was recorded does not change as a
23 result of any specific retirement, PPL Electric's depreciation accrual does not

1 change as a result of the retirement. The annual accrual per books is the result
2 of applying the accrual rate to the net plant balance, and neither changes as a
3 result of a retirement. Therefore, there should be no adjustment to depreciation
4 expense due to the retirement of DSIC eligible property.

5 As a result of the plant addition, however, the plant balance to which the
6 accrual rate is applied increases, and therefore, PPL Electric's annual
7 depreciation accrual, per books, increases as a result of the plant addition. The
8 treatment of depreciation related to replacement of plant eligible for the DSIC
9 proposed by PPL Electric reflects PPL Electric's depreciation accounting per
10 books, and it is appropriate for ratemaking to follow plant accounting in these
11 matters. I note also that PPL Electric's DSIC proposal in this regard follows
12 exactly procedures employed by water and sewer utilities in their Commission-
13 approved DSICs or CSICs.

14 Q. How do you respond to the assertion that the Company has failed to demonstrate
15 a need for DSIC?

16 A. PPLICA witness Baron asserts that the Company has failed to identify any
17 "changed circumstances" that would necessitate the establishment of a DSIC.
18 The Company responds that, in fact, circumstances have changed and, although
19 the consequences of those changes have yet to be experienced, the Company's
20 DSIC proposal is designed to avoid future adverse consequences that may be
21 experienced by the Company and its customers. The "changed circumstances"
22 that the DSIC proposal responds to are the aging of the Company's distribution
23 infrastructure.

1 In analyzing its distribution plant, the Company has identified concerns
2 regarding the age of plant and the fact that a significant amount of plant will need
3 to be replaced in the not too distant future. Records show that 106,050 poles
4 were installed during the 1950's, but with increased demand for electricity, that
5 number grew to 184,104 installed during the 1960s and 234,046 installed during
6 the 1970s before dropping to 157,424 during the 1980s and 136,530 during the
7 1990s. As the large numbers of poles installed during the 1960s and 1970s age,
8 the number of poles that will require replacement will grow dramatically.

9 Other plant accounts show similar results. This is not surprising because
10 other areas of our nation's infrastructure including highways, bridges, water
11 systems, and sewer systems also are aging. PPL Electric sees this as a
12 "changing condition" and has proposed DSIC as a proactive measure to
13 anticipate an increasing need for capital to address the issues associated with
14 aging infrastructure and to manage that issue so that it does not adversely
15 impact customers.

16 Q. How do you respond to the criticism that collecting DSIC on a kWh basis is
17 inappropriate?

18 A. The Company believes that such a collection mechanism is appropriate based on
19 the following considerations:

- 20 • As proposed, DSIC would be limited to not more than 5% of distribution
21 charges. This safeguard limits the amount of additional usage-based
22 charges that can be reflected in rates.

- 1 • As proposed, the DSIC would be reset to zero in base rate proceedings so
2 there would, in fact, be no usage-based charges for up to a year following
3 a base rate proceeding.
- 4 • The annual review and reconciliation of a kWh mechanism is much
5 simpler and more reliable than a reconciliation of a demand-based charge,
6 the most likely other alternative, because residential demand is
7 determined by load survey whereas usage is measured directly. The
8 Company believes that this improves the auditability of DSIC.

9 Q. OSBA, DOD, PEC and PPLICA have argued that recovering the DSIC on a
10 uniform amount per kWh basis caused a greater portion of DSIC costs to be
11 recovered from large customers. Are these concerns valid?

12 A. These criticisms are arithmetically correct to the extent that recovery of DSIC
13 expenses based upon a uniform amount per kWh would tend to recover
14 proportionately more DSIC costs from large customers. In order to address
15 these concerns, PPL Electric, as an alternative, is willing to calculate the DSIC as
16 a percentage to be applied to distribution rates. In that way, DSIC recoveries
17 would follow the Commission's allocations of plant in this proceeding as reflected
18 in rates for distribution service. Use of a uniform percentage would reduce
19 overall DSIC charges to large customers. I note that the DSICs of water
20 companies are expressed as a percentage, and not as an amount per thousand
21 gallons or hundred cubic feet of water. *Re. Pennsylvania-American Water Co.*,
22 86 Pa. PUC, *supra*, p. 424. Thus, use of a uniform percentage applied to
23 distribution rates would make PPL Electric's proposed DSIC similar to the DSICs

1 that the Commission has approved for water utilities and the CSICs that have
2 been approved for sewer utilities.

3 Q. Witness Epstein asserts that the proposed DSIC is discriminatory because it
4 would only be applied to customers taking service at 12,470 volts or below. How
5 do you respond to the assertion that DSIC is discriminatory?

6 A. The Company proposes to exclude customers taking service above 12,470 volts
7 because those customers are not served by the distribution system (other than
8 metering, billing, and other common costs) and, therefore, do not benefit from the
9 investments in the distribution system designated as eligible for collection under
10 the proposed DSIC. The Company does not view its proposal as discrimination
11 toward customers served at lower voltages, but rather as an issue of being fair to
12 the customers who take service at the higher voltage levels.

13 Q. Some parties have argued that the annual process proposed by PPL Electric for
14 its DSIC is unrealistic (OCA Statement No. 2, pp. 5, 9-10). Are such concerns
15 valid?

16 A. No, they are not. Initially I note that the DSICs of water utilities and the CSICs of
17 sewer utilities are filed quarterly, effective upon one month's notice. Re:
18 *Pennsylvania-American Water Co.*, 83 Pa. PUC 415, 423 (1986). I am not aware
19 of any procedural problems caused by these filings. PPL Electric also proposes
20 to file its DSIC on one month's notice, but it will be filed only once each year,
21 thereby imposing far less burden on the Commission than the DSICs of water
22 utilities.

1 Given the fact that water DSICs have been in effect for approximately
2 eight years, with rates changing four times each year upon one month's notice,
3 there is no reason to believe that a similar process proposed by PPL Electric
4 would be as difficult as has been suggested.

5 Further, PPL Electric itself has experience with changes of rates upon
6 exactly the same schedule as the Company has proposed for the DSIC in this
7 proceeding. This schedule has worked for the reconciliation and annual
8 adjustment of PPL Electric's Intangible Transition Charges ("ITCs") and
9 Competitive Transition Charges ("CTCs").

10 Q. Certain parties have contended that the DSIC is inappropriate because it would
11 permit rate changes without regulatory review of rates (OCA Statement No. 2,
12 pp. 5, 10; PPLICA Statement No. 1, pp. 46-50). Are such concerns justified?

13 A. No, they are not. Initially, I note that the rates would not change without
14 Commission approval. Supplement No. 38 to Tariff – Electric Pa. P.U.C. No.
15 201, p. 19Z.3. Further customers will have a full and fair opportunity to challenge
16 the DSIC in general or the specific charge that is in effect at any time. If any
17 customer affected by the DSIC wishes to challenge it, such issues could be
18 raised in a standard complaint. PPL Electric's DSIC will not escape regulatory
19 review.

20 Q. Certain parties have contended that the DSIC is inappropriate because PPL
21 Electric will need to implement accounting and information systems to track costs
22 and identify specifically plant additions eligible for the DSIC (OCA Statement No.
23 2, p. 9). Are these contentions justified?

1 A.: No, they are not. Upon the Commission's approval of the DSIC, PPL Electric will
2 implement all accounting and information systems that are needed to track DSIC
3 plant additions, costs and revenues. PPL Electric will submit to the Commission
4 information preserved through such systems in its annual filings and annual
5 reconciliations. Again, as I have noted with regard to the water utility DSIC and
6 the sewer utility CSIC, they present the same implementation issues as does
7 PPL Electric's proposed DSIC, but substantial problems have not materialized
8 with regard to the water utility DSICs or sewer utility CSICs.

9 Q. Are there any other points raised by other parties that you wish to address?

10 A. Yes. On page 17 of his testimony, Witness Epstein states, "Additionally, the '\$26
11 million in property additions' that PPL believes is 'eligible' under DISC surcharge
12 should be rejected in its entirety." If by this statement Witness Epstein means
13 that no property additions should be eligible for recovery under DSIC, then I
14 believe that I have already provided rebuttal testimony on that point. However, if,
15 by his statement, Witness Epstein is saying that such additions should never be
16 reflected in rate base, then the Company responds as follows:

- 17 1. The \$26 million represents the Company's estimate of plant additions in
18 2005 that would meet its eligibility definition. Those additions are not being
19 claimed as additions to rate base in this proceeding.
- 20 2. The Company believes that property additions that meet its eligibility
21 definition represent prudent investments necessary to provide reliable
22 service to customers that should be included in rate base.

Transmission Service Charge

- 1
- 2 Q. Please describe the Company's proposal in this case regarding the
- 3 establishment of a Transmission Service Charge ("TSC").
- 4 A. PPL Electric's current tariff permits it to charge all of its Provider of Last Resort
- 5 ("POLR") customers for FERC-approved transmission charges. The Company
- 6 has proposed a transmission rate tracking mechanism that would function in a
- 7 manner similar to the former Energy Cost Rate. The proposed tracker would be
- 8 reset annually to (1) reflect the current level of transmission charges and forecast
- 9 of POLR sales and (2) a reconciliation of prior year collections to costs.
- 10 Q. Have other parties criticized PPL Electric's proposed TSC?
- 11 A. Yes. Several parties have opposed various portions of PPL Electric's proposed
- 12 TSC. However, no party has opposed PPL Electric's recovery of its transmission
- 13 service costs.
- 14 Q. Can you summarize those criticisms and respond to them?
- 15 A. Yes, I can. Several parties have indicated that, in their view, recovery of
- 16 transmission service expenses should not be subject to reconciliation (OTS
- 17 Statement No. 5, p. 13; PPLICCA Statement No. 1, p. 28; Pennsylvania Energy
- 18 Consortium Statement No. 1, p. 11). Such contentions are based, in part, on
- 19 such parties' interpretations of various provisions of the Public Utility Code. PPL
- 20 Electric will respond fully to such legal arguments in its briefs. My previous
- 21 discussion of the legality of automatic adjustment clauses with regard to PPL
- 22 Electric's proposed DSIC substantially applies also to the proposed TSC.

1 These parties contend also that, in their view, recovery of transmission
2 service charges should not be subject to reconciliation as a matter of public
3 policy. Such contentions are erroneous. Reconciliation of recovery of
4 transmission service costs through an automatic adjustment clause is
5 appropriate because the expenses are substantial, the expenses are subject to
6 substantial variation and the variation is beyond the control of the utility.

7 Clearly, transmission service charges are substantial. As shown on
8 Exhibit Future 1, Schedule D-3, page 1, projected transmission revenues to be
9 collected from POLR customers during 2004 are approximately \$143 million,
10 which is substantial especially when compared to PPL Electric's projected
11 distribution revenues for the same period of \$500 million. For 2005, with the
12 expiration of the rate cap, transmission service revenues are expected to
13 increase by approximately \$57 million to match the actual amounts charged to
14 PPL Electric by PJM. Thus, total transmission service charges for 2005 are
15 expected to be approximately \$200 million (\$143 million + \$57 million) which is
16 approximately 29 percent of PPL Electric's distribution revenues at proposed
17 rates (\$200 million + \$688 million.) For distribution revenues at proposed rates,
18 see Exhibit Future 1, Schedule D-1.

19 Although increases in transmission service charges may not be of this
20 magnitude in the years immediately after 2005, the Company expects substantial
21 annual changes in the levels of transmission service charges in the future.
22 History supports this belief as transmission costs to serve POLR load have been
23 \$139,950,000 in 2000, \$178,406,000 in 2001, \$170,329,000 in 2002, and

1 \$194,350,000 in 2003. Levels of transmission charges will vary in the future
2 based upon the total amounts of transmission costs incurred by members of the
3 PJM Interconnection, Inc. ("PJM"), changes in procedures under the PJM's Open
4 Access Transmission Tariff ("OATT") by which transmission expenses are
5 apportioned among the load serving members of the PJM such as PPL Electric
6 and changes in the amount and seasonality of the peak and annual load of PPL
7 Electric's POLR customers. PPL Electric's POLR customers' load data are the
8 input from PPL Electric for the PJM transmission allocation procedures set forth
9 in the OATT.

10 Further, PPL Electric's transmission service charges are not subject to its
11 control. As indicated above, such charges are imposed under PJM's OATT.

12 PPL Electric does not control PJM. Although PPL Electric is a voting member of
13 the PJM, it casts only one vote among over 200 voting members. Furthermore,
14 in accordance with PJM bylaws, the vote of the membership is simply a
15 recommendation to the PJM Board which has ultimate decision-making authority.
16 Thereafter, any change to PJM's OATT must be proposed to the Federal Energy
17 Regulatory Commission ("FERC") for its consideration. It cannot be contended
18 that PPL Electric controls the procedures under which transmission expenses are
19 allocated to it.

20 Nor does PPL Electric control the basis on which these transmission
21 expenses are allocated. The principal data which are used to allocate
22 transmission expenses among load serving entities in the PJM are their
23 contributions to the coincidental peaks of the PJM and their annual kWh usage.

1 Such factors are simply the accumulation of usage by all of PPL Electric's POLR
2 customers. PPL Electric gathers the data and provides the data, but PPL Electric
3 does not control the data. The data reflect customers' usage, and customers
4 control their usage, not PPL Electric. Thus, PPL Electric cannot control any
5 element of the process by which transmission service expenses are charged to it.

6 Q. Should PPL Electric's recovery of transmission expenses be subject to a
7 prudence review, as suggested by the OTS (OTS Statement No. 5, p. 15)?

8 A. No, it should not. The OTS refers to the Commission's annual investigations of
9 recovery of purchased gas costs by large local natural gas distribution
10 companies under Section 1307(f) of the Public Utility Code as an example of an
11 appropriate prudence review. OTS' analogy is flawed. In fact, when the annual
12 reviews of purchased gas cost decisions are analyzed, they demonstrate why no
13 prudence review is appropriate for transmission expenses.

14 As explained above, PPL Electric cannot control its charges from the PJM
15 for transmission services under the OATT, which is part of a FERC-approved
16 tariff. Total charges are based entirely upon procedures established by the PJM
17 subject to FERC approval and by PPL Electric's POLR customers' usage. Nor
18 can PPL Electric "shop around" for transmission services. PJM provides the
19 transmission services and the cost of those services is governed by PJM's
20 OATT. Therefore, there is no opportunity for transmission shopping on the PJM.

21 In contrast, local natural gas distribution companies, which are subject to
22 annual Section 1307(f) investigations, can control many aspects of their
23 purchased gas costs. Local natural gas distribution companies control the levels

1 of pipeline transportation and storage capacity for which they contract. It is
2 possible for a local natural gas distribution company to contract for more capacity
3 than needed to meet its customers' requirements. In addition, depending on the
4 pipeline system, a local natural gas distribution company may be able to obtain
5 pipeline capacity or storage capacity from any of several suppliers. Shopping for
6 pipeline and storage capacity may be available.

7 Further, local natural gas distribution companies may choose among a
8 wide variety of suppliers of natural gas for the commodity. Natural gas
9 distribution companies also choose the type of contract under which they
10 purchase natural gas. Natural gas may be purchased in the spot market or
11 under longer term contracts and at variable or fixed rates. There is no equivalent
12 for electric distribution companies with regard to transmission expenses on the
13 PJM.

14 Local natural gas distribution companies make all of these decisions, and
15 each of these decisions can have substantial impacts on customers. Because
16 local natural gas distribution companies exercise substantial discretion over their
17 natural gas purchases and transportation, it is reasonable for the Commission to
18 review their use of such discretion to make certain that it was exercised for the
19 benefit of the public.

20 Unlike local natural gas distribution companies, there is, as a practical
21 matter, nothing for the Commission to review with regard to transmission service
22 charges. PPL Electric realistically has no discretion with regard to the level of
23 transmission expenses that it incurs on the PJM; there is no exercise of

1 discretion for the Commission to review. Therefore, a prudence review of PPL
2 Electric's transmission expenses would be unnecessary and wasteful.

3 Q. OTS also contends that PPL Electric's present tariff does not provide for
4 automatic pass through of transmission costs (OTS Statement No. 5, p. 15). Do
5 you agree with that contention?

6 A. No, I do not. OTS correctly acknowledges that all rate schedules of PPL
7 Electric's presently-effective tariff contain the following language:

8 "The Company will provide and charge for transmission service
9 consistent with the PJM Open Access Transmission Tariff approved
10 or accepted by the Federal Energy Regulatory Commission for
11 customers who receive Basic Utility Supply [POLR] Service from
12 the Company unless such customers obtain transmission service
13 from another provider."

14 This tariff language became effective pursuant to the Commission's approval of
15 the "Joint Petition for Full Settlement of PP&L, Inc.'s Restructuring Plan and
16 Related Court Proceedings" in the Final Order entered on August 27, 1998, in
17 *Application of Pennsylvania Power & Light Company for Approval of its*
18 *Restructuring Plan under Section 2806 of the Public Utility Code,* at Docket No.
19 R-00973954. All parties to that proceeding joined in the settlement. Pursuant to
20 this tariff language, PPL Electric has charged POLR customers an unbundled
21 rate for transmission service since January 1, 1999.

22 The OTS interpretation of the above-quoted provision of PPL Electric's
23 tariff is inconsistent with its plain language. PPL Electric can "provide and

1 charge” for transmission service consistent with the PJM OATT only if PPL
2 Electric can pass through its actual charges from the PJM to its POLR customers
3 on a timely basis as the OATT is changed from time to time subject to FERC’s
4 regulatory review. Although the above-quoted tariff provision does not set forth
5 the precise mechanics by which such results are to be accomplished, it does
6 make clear that PPL Electric is to charge for transmission service consistent with
7 the PJM OATT. OTS’ proposal would render the above-quoted provisions of
8 PPL Electric’s tariff meaningless.

9 In essence, PPL Electric’s TSC proposal in this proceeding merely
10 provides specific procedures for implementation of the tariff provision established
11 in PPL Electric’s restructuring proceeding that permits PPL Electric to charge
12 POLR customers for transmission service consistent with the PJM OATT.

13 Q. OTS contends that transmission service charges incurred by PPL Electric should
14 be recovered as “an unbundled transmission rate that is non-reconcilable” (OTS
15 Statement No. 5, p. 13). Do you agree with this proposal?

16 A. No, I do not. The proposal is incorrect for the reasons which I have explained
17 previously. If, however, the Commission were to determine that the OTS
18 proposal should be adopted, and that PPL Electric should recover transmission
19 expenses as an unbundled transmission rate that is not reconcilable, then the
20 appropriate level of transmission service expenses to be recovered by PPL
21 Electric based upon the best available information in this proceeding would be
22 0.564 cents per kWh. This amount reflects the total amount of annual
23 transmission service charges projected to be incurred by PPL Electric during the

1 2004 test year of \$198,973,679 divided by projected retail kWh sales of
2 35,342,287,000 kWh. These figures reflect adjustments for price response and
3 contract customers who pay for transmission service through those rates and the
4 dollar amount reflects gross receipts tax at the rate of 59 mills. This information
5 is contained in Exhibit DAK2.

6 Q. Is this also the rate PPL Electric proposes to charge in 2005 if the TSC is
7 approved?

8 A. Yes. While PPL Electric's proposal for TSC involves end-of-year filings, that
9 process must be modified this year in light of the expectation that the
10 Commission will not issue a Final Order in this proceeding until December 2004.
11 In order to address this situation, the Company wishes to establish in this
12 proceeding that the transmission costs to be collected from POLR customers
13 during 2005 are \$198,973,679 and that the associated rate, consistent with the
14 Company's proposed collection mechanism, is 0.564 cents per kWh.

15 Q. Do you agree with OCA witness Morgan's comments regarding changes in PPL
16 Electric's projections for revenues from Point-to-Point (PTP) service for 2004?

17 A. No. First it must be understood that the projected \$3.4 million dollar reduction in
18 PTP revenues between the 2003 historic test year and the 2004 future test year
19 was based on the assumption that the FERC order to eliminate regional through
20 and out rates (RTORs) would be effective April 1, 2004 (not April 4, 2004 as
21 stated by Mr. Morgan). The subsequent settlement (at FERC Docket No. EL01-
22 111) postponed the elimination of RTORs until December 1, 2004. PPL Electric's
23 update of its 2004 projected revenues from PTP service is \$4.1 million, which is

1 \$2.9 million, not \$3.4 million, lower than the 2003 historic test year revenues of
2 \$7.0 million.

3 Q. Does the updated \$2.9 million decrease in the projected PTP revenues change
4 the projected \$57.2 million increase in transmission service charges projected by
5 PPL Electric?

6 A, No. The transmission revenue requirement which is projected to increase by
7 \$57.2 million is based on the transmission service charges that PPL Electric
8 expects to be billed by PJM under the PJM Open Access Transmission Tariff
9 (OATT) as a Load Serving Entity (LSE) providing service to POLR customers.
10 The revenues PPL Electric receives from PJM as its share of other parties' PTP
11 reservations on the PJM system are recovered pursuant to FERC jurisdictional
12 PJM agreements and consistent with PPL Electric being a transmission owner in
13 PJM. The revenue PPL Electric receives as a transmission owner is separate
14 and distinct from the transmission service charges PPL Electric incurs as a Load
15 Serving Entity providing service to POLR customers. Revenues that PPL Electric
16 receives as a transmission owner are reflected in Exhibit Future 1, Statement D-3
17 on the line "Other Electric Revenues" under the heading "Transmission Rate
18 Revenue." Both the costs and revenues associated with PPL Electric's provision
19 of transmission service as a transmission owner have been removed from the
20 distribution revenue requirement in this case. Thus, any adjustment would be to
21 these figures and would not affect the Company's distribution revenue
22 requirement or the transmission service charges it incurs as an LSE under the
23 PJM OATT.

1 Q. Wouldn't the reduction in revenues to transmission owners ultimately reduce the
2 amount paid by LSEs?

3 A. In theory, yes, but not for PPL Electric as a POLR provider. The adjustment
4 identified by witness Morgan relates to PTP service, not Network Integration
5 Transmission Services. PPL Electric, as an LSE, does not purchase PTP service
6 to supply its POLR load. The change in PTP revenues, therefore, would not
7 affect the costs it incurs as an LSE.

8 Q. Several parties have criticized PPL Electric's proposed allocation of transmission
9 service charges among classes of customers based upon POLR energy sales,
10 that is, a uniform amount per kWh, regardless of the customer class. Do you
11 agree with such criticisms?

12 A. In my direct testimony, PPL Electric Statement No. 4, I explained that PPL
13 Electric's proposed allocation of transmission service charges among rate
14 classes and customers within each rate class based on kWh of POLR sales is
15 desirable for two important reasons. First, the proposed allocation is simple in
16 that it is easily understood by customers and easily applied. Second, such
17 allocation helped PPL Electric to meet its rate allocation objective of having no
18 single rate class, as a whole, experience increases in its total bills in excess of
19 10 percent. For these reasons, PPL Electric continues to believe that its initial
20 proposed allocation of transmission service charges is preferable to alternatives
21 suggested by other parties.

22 Having said that, however, it must be acknowledged that pursuant to the
23 PJM OATT, approximately 70 percent of transmission service charges incurred

1 by PPL Electric are allocated on the basis of POLR customers' contributions to
2 coincident peaks on the PJM system; although, because only 27% of the load is
3 recorded on interval meters, about 73% of this component is distributed to rate
4 schedules and customers on a pro rata basis consistent with their kWh usage –
5 not their actual demand. The remaining 30 percent of transmission service
6 charges are allocated by PJM among load serving entities based upon kWh of
7 sales.

8 In considering whether to re-allocate transmission charges, the
9 Commission should be aware that allocations of transmission service expenses
10 among customer classes or rate schedules based upon principles of cost
11 causation could vary substantially from year to year. The reason for such
12 substantial variation is that PPL Electric has experienced both winter and
13 summer peaks. For example, over the last four years, PPL Electric has been a
14 winter peaking company in 2000 and 2003 and a summer peaking company in
15 2001 and 2002. Whether PPL Electric's load peaks in the summer or in the
16 winter can change from year to year, and there is no clear trend that either
17 summer peaking or winter peaking will become dominant in the near future.

18 If the Commission were to determine that transmission charges should be
19 allocated based upon principles of cost causation, PPL Electric would reallocate
20 charges annually, consistent with PJM OATT procedures, based upon its actual
21 peak – either winter or summer – during the prior year ended November 30.
22 Allocations among customer classes based upon summer peaks produces
23 substantially different results from allocations based upon winter peaks.

1 To illustrate the effect of peaks in different seasons, I have calculated, for
2 illustrative purposes, the allocations of transmission expenses and rates among
3 the rate schedules based upon the winter peak in 2003 and the summer peak in
4 2002. Exhibit DAK3 shows rates based upon allocations reflecting the 2003
5 winter peak. Exhibit DAK4, in contrast, shows rates based upon allocations
6 reflecting the 2002 summer peak. To make the rates comparable, these two sets
7 of rates are designed to recover the same total amount of transmission charges.
8 As can be seen by comparing the two schedules, the allocations among rate
9 schedules and customer classes vary substantially based upon whether the 2002
10 summer peak or 2003 winter peak is used to allocate transmission service
11 charges. I note that this variability of the allocations among rate classes is a
12 further reason why PPL Electric should recover transmission service charges
13 based upon annual rate adjustments with reconciliation.

14 The rates in Exhibit DAK3 are illustrative of the rates that would go into
15 effect on January 1, 2005, for recovery of transmission expenses if the
16 Commission determines that PPL Electric should recover transmission charges
17 through an unbundled transmission rate under which transmission charges are
18 allocated among the rate schedules based upon principles of cost causation.
19 The exact rates would be determined as part of PPL Electric's compliance filing.
20 Under this proposal, the charges are allocated among rate schedules based
21 upon the procedures set forth in the PJM OATT. Transmission charges would
22 then be recovered within each rate schedule based upon a uniform rate per kWh.

1 Q. PPLICA has proposed that, for those classes of customers with interval meters,
2 transmission rates be developed on a demand/energy basis to follow more
3 precisely the PJM OATT procedures (PPLICA Statement No. 1, pp. 13-18). Do
4 you agree with this proposal?

5 A. No. In my opinion, developing demand/energy rates for recovery of transmission
6 charges within rate schedules for large customers is an unnecessary
7 complication that will make little practical difference given the similar load
8 characteristics of large customers. If the Commission were to approve the
9 PPLICA proposal, however, it is critical that reconciliation be implemented on
10 either a demand basis or an energy basis, but not both. Reconciliation over two
11 rate elements would be extremely difficulty to implement and administer.

12 Q. Do you have any other alternatives for consideration by the ALJ, the Commission
13 and the parties?

14 A. Yes. Exhibit DAK3 also contains, as another alternative, illustrative rates for
15 recovery of transmission charges for each of three broad classes of customers.
16 This approach allocates transmission charges based upon principles of cost
17 causation among three broad categories and recovers those transmission
18 charges within each broad class based upon kWh of sales. The use of fewer
19 groupings for recovery of transmission charges would promote rate stability and
20 simplify administration of recovery of transmission expenses.

21 Under this alternative, the first class of customers would be all residential
22 customers. The second class would include smaller commercial, industrial and
23 municipal customers served under Rate Schedules GS-1, GS-3, BL, GH, IS-1.

1 and all lighting rate schedules. The third group of customers would be large
2 customers served under all large power, interruptible and price response rate
3 schedules. These are the same groups that are used for reconciliation of PPL
4 Electric's Competitive Transition Charges ("CTCs") and Intangible Transition
5 Charges ("ITCs"). Again, these rates are for illustrative purposes, only, and exact
6 rates for 2005 would be calculated as part of the compliance filing.

7 Q. If the Commission were to decide that a portion of transmission service charges
8 should be allocated on a demand basis, does PPL Electric have a specific
9 proposal for reconciliation of transmission expenses under these circumstances?

10 A. Yes, PPL Electric does have such a proposal. As an alternative to PPL Electric's
11 preferred method of recovering costs and reconciling recoveries based upon the
12 uniform amount per kWh of sales, PPL Electric would be willing to follow a
13 procedure very similar to those approved by the Commission in PPL Electric's
14 restructuring proceeding for recovery and reconciliation of CTCs and ITCs.

15 PPL Electric would be willing to allocate costs among rate schedules
16 based upon procedures set forth in PJM's OATT, as amended from time to time
17 subject to FERC approval. PPL Electric, however, would reconcile recoveries
18 with expenses not by individual rate schedule, but by the three broad classes of
19 customers identified previously. The three groups of customers for reconciliation
20 would be the same as those for the alternative proposal for recovery of
21 transmission expenses. Reconciliation by large, broad groups, instead of
22 individually by the numerous rate schedules will reduce volatility in rates due to
23 small or variable kWh sales for the smaller, individual rate schedules. Using

1 broad categories for purposes of reconciliation also will reduce substantially the
2 costs of administering the recovery of transmission charges.

3 **Allocation of Distribution Revenue Requirements**

4 Q. Please describe the Company's proposal in this case regarding the allocation of
5 distribution revenue requirements.

6 A. While PPL Electric believes in the principle that customer rates should reflect the
7 costs those customers place on the distribution system, there are certain aspects
8 of this request that would result in significant disruptions to the rates of certain
9 customer classes if that principle is strictly followed. PPL Electric believes that a
10 gradual approach is appropriate and, accordingly, the allocations proposed by
11 the Company are intended as a first step and reflect the following objectives:

- 12 1. Keep the increase on a total-bill basis to all residential rate schedules
13 below 10%. "Total-bill" basis means that the allocation process included
14 both the distribution increase proposed in this case and an estimate of the
15 increase in the transmission service charge pass-through that will also
16 occur on January 1, 2005.
- 17 2. Keep the increase on a total-bill basis to all rate schedules below 10%.
- 18 3. Bring the rate of return for customers taking service at 69,000 volts closer
19 to the system average rate of return.

20 Q. Please describe the issues raised by other parties.

21 A. PPLICA witness Stephen Baron, DOD witness Kenneth Kincel, and OSBA
22 witnesses Robert Knecht and Mark Ewen, while generally acknowledging that
23 cost of service based allocations may be tempered by other factors, argue that

1 PPL Electric's proposal does not go far enough in the direction of cost-based
2 allocations. Although the details of each witness's proposal are different, all
3 recommend some amount of gradualism as evidenced by the fact that none
4 recommends a strict adherence to cost causation principles. The disagreement
5 appears, then, to not be one of approach, but one of degree.

6 Q. Do any parties agree with PPL Electric's proposal?

7 A. Yes. OCA witness Richard Galligan supports PPL Electric's approach. OCA
8 witness Galligan observes, correctly in PPL Electric's opinion, that, when viewed
9 as a whole, electric rates remain in a transitional period until the generation rate
10 cap expires. It is, therefore, unnecessary and inappropriate to move rapidly to
11 "correct" the allocation of distribution revenue requirements when other bill
12 components that remain capped may continue to be "incorrect." PPL Electric
13 agrees with OCA witness Galligan that "considerations such as gradualism,
14 stability, understandability, acceptance, simplicity, etc." are important issues for
15 commissions to factor into the setting of rates.

16 Q. Has the Company's proposal changed in light of the issues raised by PPLICA,
17 DOD, and OSBA?

18 A. No, it hasn't. The Company continues to believe that the combined impact of
19 changes in distribution rates and the transmission service charge pass-through
20 should be considered in the context of their impact on the total bill. The
21 Company also continues to believe that 10% is an important threshold, especially
22 considering that electric rates are in the middle of a transition that will provide
23 other opportunities, such as the completion of stranded recoveries, to achieve

1 additional "corrections" without introducing disruptive distortions of individual
2 unbundled components.

3 Q. Does the Company have an opinion as to how proposed revenue allocations
4 should be adjusted in the event that overall revenue requirements granted in this
5 proceeding are lower than the amount requested by the Company.

6 A. PPL Electric believes that a proportional scale-back across all rate schedules
7 would be the most appropriate approach. The Company acknowledges that the
8 scale-back could be skewed across rate schedules in order to provide additional
9 movement toward cost-based allocations. However, such an approach could be
10 considered unfair from the perspective of a party who successfully advocated a
11 revenue reduction, but then may not benefit from the result of that advocacy.

12 Consistent with the views of OCA witness Galligan regarding gradualism, the
13 Company believes that the incremental movement that might be achieved by a
14 scale-back on a non-proportional basis, a departure from normal Commission
15 practice, would be relatively small. When balanced against other considerations,
16 such an approach would be inappropriate.

17 **Amortization and Collection of Hurricane Isabel Costs**

18 Q. Please describe the Company's request regarding the recovery of costs
19 associated with Hurricane Isabel.

20 A. On October 20, 2003, PPL Electric requested Commission authority to defer, for
21 accounting and financial reporting purposes, losses arising from severe damage
22 caused by Hurricane Isabel and to amortize those losses for recovery from
23 customers in a future base rate proceeding. Hurricane Isabel struck PPL

1 Electric's service territory most heavily during the evening of September 19, 2003
2 and the morning of September 20, 2003. The losses which PPL Electric sought
3 to defer were increases in operation and maintenance, customer, and general
4 administrative expenses incurred by the Company in preparing to respond to the
5 damage from Hurricane Isabel, restoring service to customers, assisting
6 customers during the service interruptions, and repairing facilities damaged by
7 the storm. In its petition, PPL Electric specifically acknowledged that it was not
8 requesting that the Commission decide, at that time, whether its deferred losses
9 were recoverable from customers. PPL Electric stated in its petition that
10 approval to recover such losses as well as the length of the amortization would
11 be determined in a future rate base proceeding. The Commission granted PPL
12 Electric's request to defer storm-related losses for accounting and financial
13 reporting purposes in an order entered on January 16, 2004 at Docket No.
14 P-0032069. In this case, PPL Electric is requesting amortization of \$15 million in
15 costs related to Hurricane Isabel over a period of five years. This request is
16 included as an adjustment to Operating and Maintenance Expense in the future
17 test year.

18 Q. Please describe the issues raised by other parties.

19 A. OCA witness Thomas Catlin argues that the costs were incurred during the
20 period that distribution and transmission rates were capped and that, on advice
21 of counsel, recovery of those costs subsequent to the expiration of the rate cap
22 would constitute a de facto exception to the cap in violation of the Electricity
23 Generation Customer Choice and Competition Act ("the Competition Act") and

1 PPL Electric's Restructuring Settlement (Docket No. R-00973954). OCA witness
2 Catlin further argues that, in the event the Commission determines that these
3 costs are recoverable, the portion of the \$15 million associated with regular
4 salaries, wages, and benefits would have been incurred regardless of whether
5 the Hurricane occurred and should, therefore, be excluded. OTS witness
6 Charles Weakley also argues that regular salaries, wages and benefits should be
7 excluded. OTS witness Weakley also argues that a 10 year amortization period
8 is more appropriate. Witness Eric Epstein argues that collection of costs related
9 to Hurricane Isabel would be a violation of the rate cap provisions of the
10 Competition Act. Witness Epstein further argues that if the Company is entitled
11 to rate recovery for extraordinary weather then consumers are also entitled to
12 refunds when the loss of service due to those extraordinary conditions results in
13 quantifiable hardships.

14 Q. How do you respond to the assertion that recovery of these costs would
15 constitute a violation of the rate cap provisions of the Competition Act?

16 A. Counsel advises me that collection of these costs would not be a violation of the
17 rate cap provisions of the Competition Act. The Competition Act specifies, in
18 Section 2804(4)(1)(B), that "the charges of the utility for non-generation services
19 that are regulated as of the effective date of this chapter...shall not exceed the
20 non-generation charges that have been approved by the Commission for such
21 service as of the effective date of this chapter." The Competition Act is silent on
22 the issue of the recovery of costs incurred during the cap period except on the
23 point that charges during the cap period cannot exceed the capped levels. PPL

1 Electric did not request these costs incurred in 2003 be recovered during 2004;
2 i.e., during the cap period. PPL Electric requests that they be recovered starting
3 in 2005; i.e., after the cap period. PPL Electric's request is entirely consistent
4 with the Competition Act.

5 Q. How do you respond to the assertion that regular salaries, wages, and benefits
6 should be excluded from any claim?

7 A. At the start of each year, the Company identifies a scope of work that is
8 necessary to maintain its facilities and to assure an appropriate level of reliability.
9 Activities included in that scope include tree trimming, inspections, testing,
10 preventative maintenance, and repairs. Staffing plans are made consistent with
11 the scope of work. When an event like Hurricane Isabel occurs, all available
12 resources are engaged in storm-related restoration and repair and none of the
13 planned scope of work is done. Nevertheless, that planned work must be
14 completed within a reasonable period of time after storm-related work is
15 completed and overtime and contracting are employed to get the work done.
16 While the Company cannot identify each individual project that incurred
17 contracting and overtime costs as a result of regular time and salaries being
18 devoted to storm-related efforts, the regular salaries accumulated under the
19 storm account provide an estimate of that impact. Such costs are real costs
20 experienced by the Company as a result of the storm.

21 Q. How do you respond to the recommendation that these costs be amortized over
22 a ten year period instead of a five year period?

1 A. OTS witness Weakley's only rationale for a longer recovery period is that "PPL
2 has not experienced a storm the size of Hurricane Isabel for an extended period"
3 and, therefore, should recover allowable costs over an extended period. In fact,
4 the Company acknowledges that it has never in its 80 year history experienced a
5 storm of the magnitude of Hurricane Isabel in terms of the number of cases of
6 trouble. However, this does not mean that it would be appropriate to recover the
7 costs of Hurricane Isabel over the next 80 years. The Company asserts that a
8 five-year period is an appropriate "extended period". In making this assertion,
9 the Company observes that it has not requested to recover a return on amortized
10 amounts not recovered. Consequently, assuming a rate of return of 8.8%
11 consistent with the Company's request in this proceeding, the proposed 5-year
12 amortization will recover \$11.7 million on a present value basis or only 78% of
13 the total amount. If OTS witness Wheatley's 10-year period is used, the recovery
14 will be \$9.7 million or only 65% on a present value basis. The effect is to punish
15 the Company for its efforts to restore customers and to accommodate their needs
16 during this unprecedented event.

17 Q. How do you respond to the assertion that customers should be entitled to a
18 refund as a result of storm-related outages?

19 A. Under the Public Utility Code, PPL Electric is required to maintain safe and
20 reasonable service which shall be reasonably continuous. The Code does not
21 require continuous service, nor does it suggest that utilities bear any liability
22 when the service they provide is reasonably continuous. Consistent with the

1 requirements of the Code, Rule 4 of the Company's Commission-approved tariff
2 (Tariff – Electric Pa. P.U.C. No. 201) states under the heading "F. Continuity":

3 “(1) The Company uses reasonable diligence to preserve
4 continuity of service, but in the event of interruption or
5 curtailment of service, Company shall not be subject to any
6 liability, penalty or payment for or on account of any such
7 interruption or curtailment...”

8 The Company does not propose any change to this language in this proceeding.

9 The intent of this language is to recognize that the Company cannot
10 anticipate and prevent all possible interruptions to or curtailment of service. The
11 Company's responsibility is to exercise reasonable diligence and, having done
12 so, *it should not be liable for the consequences of outages; especially, those*
13 *caused by Hurricane Isabel as they are beyond the Company's reasonable*
14 *control. It has not been suggested by any party that the Company failed in any*
15 *way to exercise reasonable diligence in its efforts to prepare for or restore*
16 *service following Hurricane Isabel.*

17 **Costs and Benefits Associated with AMR**

18 Q. Please describe the Company's request in this proceeding.

19 A. A significant portion of the benefits achieved by the AMR project is the
20 elimination of manual processes associated with the prior metering system. With
21 the elimination of manual processes comes the opportunity to reduce the
22 workforce. PPL Electric estimates that the deployment of AMR will ultimately
23 lead to a substantial reduction in the number of positions from what would have

1 otherwise existed without AMR. The displacement of employees carries with it
2 certain costs. PPL Electric has been able to accommodate most of these
3 displacements through normal attrition within PPL Electric; i.e., employees
4 displaced by AMR have been trained to fill vacancies that arose as a result of the
5 normal course of retirements and severance. However, with a displacement this
6 large, the normal rate of attrition has not been enough. Accordingly, the
7 Company offered enhanced severance benefits to 94 employees in order to
8 capture the payroll and benefits savings of AMR. In this proceeding, the
9 Company requested the authority to amortize the cost of these enhanced
10 benefits over a five-year period and recover the resultant amounts through rates.

11 Q. Please describe the issue raised by other parties in regard to costs and benefits
12 associated with the AMR project.

13 A. Parties raise a number of issues regarding the Company's request including the
14 accounting treatment of these costs and the assertion that recovery of these
15 costs in rates is a violation of the rate cap provisions of the Competition Act. The
16 Company's response to these concerns is included in Statement No. 2-R, the
17 Rebuttal Testimony of Joseph R. Schadt. The issue I wish to address is the
18 assertion by OCA witness Thomas Catlin that "ratepayers would be better off
19 without AMR if the amortization of the \$8,818,000 was allowed."

20 OCA witness Catlin correctly states that PPL Electric has performed an
21 analysis of the total present worth of revenue requirements associated with the
22 AMR system over a 15-year period. That analysis, as described in my direct
23 testimony (PPL Electric Statement No.4), reflected quantifiable economic

1 benefits in the form of reduced expenses. However, Statement No. 4 also
2 describes tangible benefits of a non-economic nature that customers are
3 currently enjoying as well as future economic and non-economic benefits that will
4 be available to customers as the AMR system is enhanced and as generation
5 rate caps expire. Witness Catlin's assertion that ratepayers would be better off
6 without AMR fails to recognize the benefits associated with more accurate billing,
7 more complete usage information, and outage identification and restoration that,
8 although not quantifiable in economic terms, are, nevertheless, of significant
9 value to customers. It is PPL Electric's firm belief that customers are better off
10 for having the AMR system.

11 **Proposals to Promote Retail Competition**

12 Q. Please describe the recommendations of Strategic Energy witness Jim
13 McCormick to promote retail competition.

14 A. Strategic witness McCormick makes five recommendations that he believes will
15 lead to increased retail competition in PPL Electric's service territory. These are:

- 16 1. Accelerate the enhancement of the AMR system and make data derived
17 from that system available to Electric Generation Suppliers ("EGSs").
- 18 2. Make available 12 months of usage data to EGS's for customers that have
19 authorized the release of such data.
- 20 3. Provide an updated of the Eligible Customer list.
- 21 4. PPL Electric should accept an EGS's telephonic representation that the
22 customer has authorized the EGS to obtain historical usage information.

1 5. PPL Electric should commit to having EGS Consolidated Billing available
2 within a specified period after an EGS requests it.

3 Q. Are these issues germane to a rate request involving distribution rates?

4 A. Some of the issues are appropriately addressed in a distribution case. For
5 example, the AMR system is distribution plant so the issue regarding further
6 enhancement of the AMR system is appropriately addressed here. However, the
7 issue of making additional metering data available to EGSs is not appropriate to
8 address because it relates to the generation portion of electric service which
9 remains capped under the terms of the Restructuring Settlement. Nevertheless,
10 the Company is prepared to respond to Strategic witness McCormick's individual
11 points.

12 Q. How do you respond to the request to accelerate enhancements of the AMR
13 system?

14 A. PPL Electric has stated in its direct case its expectation that the functionality of
15 its AMR system can be enhanced and that the Company expects to pursue
16 appropriate enhancements in anticipation of the end of the generation rate cap
17 on December 31, 2009. The Company is currently an active participant in both
18 the Commission's Demand-Side Response Working Group and Provider of Last
19 Resort (POLR) Roundtable – two collaborative efforts wherein future metering
20 and data requirements will be defined. The Company believes it is important to
21 work within collaboratives such as these so that the needs of all stakeholders can
22 be properly recognized in Commission orders and policies. The Company is
23 concerned about the possibility that it might undertake enhancements that would,

1 in the end, be inconsistent with whatever direction the Commission might
2 establish.

3 Currently, PPL Electric makes available to EGSs metering information
4 consistent with its Restructuring Settlement and Commission-approved supplier
5 tariff. PPL Electric intends to continue providing that information through at least
6 the term of the Settlement (currently December 31, 2009) consistent with and in
7 support of the billing, load scheduling, and load reconciliation processes
8 established in the Restructuring Settlement.

9 PPL Electric does not offer POLR service in competition with EGSs as
10 suggested by Strategic witness McCormick. POLR service is default service
11 available, consistent with the Competition Act, to customers who elect not to
12 seek supply from an EGS and to customers whose EGS fails to provide
13 contracted for supply. The price that PPL Electric charges for POLR service is
14 established by the Restructuring Settlement and cannot change, regardless of
15 the capabilities of AMR, during the term of the Restructuring Settlement.

16 In summary, PPL Electric is encouraged by the support offered by
17 Strategic witness McCormick for the Company's AMR system and for further
18 development of that system, but believes that there is no need for an accelerated
19 development and that such a development might, in fact, result in unnecessary
20 and inappropriate expenditures.

21 Q. How do you respond to the request that PPL Electric make available 12 months
22 of usage data to EGS's for customers that have authorized the release of such
23 data?

1 A. PPL Electric currently does provide EGSs with twelve (12) months of usage and
2 demand data for customers who have agreed to allow EGS's access to their
3 account data. For customers that are billed using non-interval meters, 24 data
4 points are sent per request. There are twelve (12) usage and twelve (12)
5 demand data points sent per request. For customers that are billed using interval
6 meters, one year of hourly data is sent per request. PPL Electric's standard
7 method of providing historical usage data to EGSs is through standardized
8 electronic data transactions called Electronic Data Interchange (EDI)
9 transactions. These EDI transactions are exchanged between the EGS and PPL
10 Electric according to standards established by the Commission's Electronic Data
11 Exchange Working Group (EDEWG). EGS's sends an EDI 814 historical usage
12 (HU) request to PPL Electric. The Company sends back to the supplier an EDI
13 814 HU response that PPL Electric either accepted or rejected the EGSs
14 historical usage request. Requests may be rejected because they don't match
15 an active customer account number or because the customer has indicated that
16 his usage information is not to be made available. When PPL Electric accepts
17 the EDI 814 HU, the Company sends the EGS an EDI 867 HU transaction that
18 contains the customer usage and demand information.

19 Q. How do you respond to the request that PPL Electric send "opt-out" cards to
20 customers biannually (or at some other regular interval) in order to update its
21 Eligible Customer list?

22 A. During the pilot-program and phase-in of customer choice, the number of
23 customers eligible to participate was limited and EGSs had a need to know which

1 specific customers were participating so they could market to those customers.
2 Orders implementing pilot programs and restructuring orders required utilities to
3 establish and maintain Eligible Customer Lists to address this need. PPL Electric
4 established such a list and maintained it through the completion of the phase-in,
5 which for PPL Electric was January 2, 2000. As of that date, all customers were
6 eligible for choice and there was no longer a need to identify eligible customers
7 separate from ineligible customers. PPL Electric still solicits information from
8 new customers for the purpose of responding to 814 HU requests (such as the
9 customer's willingness to release its usage to EGSs). However, PPL Electric no
10 longer maintains the Eligible Customer List.

11 Strategic witness McCormick recommends the periodic dissemination
12 of "opt-out" cards which were the mechanism by which existing customers
13 indicated whether they wished to withhold information from the Eligible Customer
14 List. Given that the need addressed by the Eligible Customer List no longer
15 exists and that the list is no longer maintained, the sending of "opt-out" cards is
16 unnecessary. Witness McCormick may, instead, be pointing to another need –
17 that being the desire of EGSs to have customer usage information to identify the
18 customers that can be served most profitably and to develop proposals for those
19 customers. Because the Eligible Customer List included historical usage
20 information, for those customers willing to allow it to be published, EGSs came to
21 rely on the List for that information. However, EDEWEG rules established the
22 historical usage request process described above as a more efficient and lower
23 cost means by which EGSs could obtain customer usage information. PPL

1 Electric assumes that the remaining issue in this regard is an individual
2 customer's willingness to make his usage information available. PPL Electric has
3 established Web-based procedures to address this issue that it believes are
4 more appropriate and less costly than the option of periodically sending 1.3
5 million post cards to customers asking them if their prior election regarding
6 confidentiality has changed.

7 Q. How do you respond to the request that PPL Electric should accept an EGS's
8 telephonic representation that the customer has authorized the EGS to obtain
9 historical usage information?

10 A. Customers' right to privacy and the confidentiality of customer information are
11 important issues that are recognized by PPL Electric and the Commission. The
12 Commission went to great lengths to establish rules regarding customer choice
13 that attempted to protect customer rights while providing EGSs reasonable
14 opportunities to bring potentially beneficial proposals to customers. An additional
15 and important concern that the Commission was attempting to address through
16 these rules was that the availability of customer information could facilitate
17 slamming. In this regard, PPL Electric is reluctant to accept a telephonic
18 representation by an EGS because the customer's intent cannot be verified.

19 Aside from choice, PPL Electric has a standing practice of requiring
20 the use of verifiable means to evidence a customer's desire to have its usage
21 information provided to any third party. PPL Electric, responding to the concerns
22 of a significant number of customers, is concerned that consultant's may
23 represent that they have the customer's approval to obtain usage information

1 when, in fact, they are acting in their own interest or in the interest of a client that
2 may be a competitor of the customer. That practice in the past required the use
3 of customer letterhead but has been since updated to accept e-mail with
4 appropriate safeguards. These practices have never included the acceptance of
5 telephonic requests.

6 Q. How do you respond to the request that PPL Electric should commit to having
7 EGS Consolidated Billing available within a specified period after an EGS
8 requests it?

9 A. At the start of the phase in of competition in 1999, PPL Electric was replacing its
10 customer information and billing system because the existing system was not
11 Y2K-compliant and because it could not be cost effectively modified to
12 accommodate the functionality necessitated by customer choice. In part
13 because the choice rules were not finalized until late in the system's design, PPL
14 Electric experienced a number of billing problems in early 1999 with choice
15 accounts. There was also some functionality that simply was not available at the
16 outset. One functionality that was not available was the ability to support EGS
17 Consolidated Billing. The Company worked closely with the Commission's Office
18 of the Executive Director during 1999 and 2000 as the Company corrected the
19 problems and deficiencies. As part of that effort it was agreed that, as long as no
20 EGSs were seeking to perform EGS Consolidated Billing, providing that
21 functionality could be a lower priority. It was agreed that if an EGS made known
22 that it wished to employ that functionality, PPL Electric would work with the
23 EGS to (1) identify interim alternatives, and (2) design and install the

1 modifications necessary to support that functionality. While no EGS has
2 indicated a need for EGS Consolidated Billing, PPL Electric has done much of
3 the design work and has completed some of the necessary modifications. The
4 Company estimates that of the originally estimated 6.700 manhours of work,
5 about 3.000 manhours of work remain. PPL Electric estimates that it will require
6 about ten months to complete the remaining work and test the modifications.
7 Because the necessary modifications affect the fundamental structure of the
8 customer support system and because they are so extensive, PPL Electric
9 anticipates that other system enhancements, including ones that may be
10 beneficial to customers, be placed on hold during the period in which EGS
11 *Consolidated Billing modifications are being made.*

12 Strategic witness McCormick's comments don't indicate a need for
13 this functionality, only that it works in Texas where customers appear, unlike in
14 Pennsylvania, to have no option regarding bill presentment. PPL Electric stands
15 by its original commitment to complete EGS Consolidated Billing upon a
16 reasonable demonstration that ratepayer money would be spent on functionality
17 that would be useful to customers. PPL Electric also is prepared to work with
18 any EGS to explore lower cost alternatives that may be available to achieve an
19 equivalent functionality.

20 Q. Does this conclude your rebuttal testimony?

21 A. Yes, it does.

PPL Electric Utilities 2004 Transmission Related Charges Forecast

2004
Forecast

	OATT Attachments	Basis Description	Basis Value	Rate (Note 3)	Forecast Charge(+)/Credit(-)	Notes
Network Transmission Service						
Payment to PJM for PPL EU LSE Non Shopping Retail Customers	H-8	PPL EU Network Transmission Service Peak Load Responsibility (PLR)	2,252,366 MWD	52.2274 \$/MWD	\$117,635,232	1
Payment to E+ for PPL EU Call Option	Power Supply Agreement	Call Option (400 MW)	146,400 MWD	52.2274 \$/MWD	\$7,646,091	1, 2
Net Network Transmission Service Charge					\$125,281,324	
Ancillaries						
OATT Schedule (Note 6)						
PJM System Control and Dispatch Service	1, 9	Real Time Net POLR Load	33,448,008 MWH	0.406 \$/MWH	\$13,579,891	5, 10
Transmission Owner Scheduling, System Control and Dispatch Service	1A	Real Time Net POLR Load	33,448,008 MWH	0.0618 \$/MWH	\$2,067,087	7
Reactive Supply and Voltage Control from Generation Sources Service	2	PPL EU Network Transmission Service PLR (PPL Share of Zone PLR)	2,252,366 MWD	5.4637 \$/MWD	\$12,306,363	4
Black Start Service	6A	PPL EU Network Transmission Service PLR	2,252,366 MWH	0.0650 \$/MWD	\$146,340	
Regulation and Frequency Response Service	3	Average Daily Regulation Obligation	42.67 MW	44.81 \$/MWH	\$1,720,420	8
Operating Reserve - Supplemental Reserve Service						
Day Ahead	6	Day Ahead Net POLR Load Forecast	34,841,875 MWH	0.1975 \$/MWH	\$6,881,231	
Real Time (Balancing)	6	Absolute Value of Real Time Net POLR Load less Day Ahead Net POLR Load Forecast	1,916,292 MWH	1.1646 \$/MWH	\$2,231,714	
Operating Reserve - Spinning Reserve Service	5	Real Time Net POLR Load	33,448,008 MWH	0.2003 \$/MWH	\$6,799,980	9
MAAC	10	Real Time Net POLR Load	33,448,008 MWH	0.0100 \$/MWH	\$334,480	
PJM West Transition Charge	11	Real Time Net POLR Load	33,448,008 MWH	0.0381 \$/MWH	\$1,274,369	9
PJM Membership		Annual Charge per Member	1 Membership	5000 \$/Membership	\$5,000	
Net Network Transmission Service Charge					\$125,281,324	
Total Ancillary Service Charge					\$62,346,876	
Total Transmission Cost					\$187,628,199	
Adjusted for GRT (5.9%)					\$189,392,348	\$0.00558 / KWH
PRS and Ration					(\$60,001)	
Less: Steelton					(\$358,688)	
Transmission Costs to Be Recovered					\$189,973,679	\$0.00564 / KWH

- Notes
- OATT Attachment H-8 - Network Integration transmission Service is \$19063/MW-Year = 52.2274/MW-Day
 - The Power Supply Agreement with PPL EnergyPlus makes requires EnergyPlus to pay for all ancillary charges associated with the "Call Option" but PPL Electric Utilities is responsible for the Network Transmission Service cost. PJM charge EnergyPlus for all cost and Electric Utilities then reimburse EnergyPlus for the Network Transmission Cost.
 - Rates based on 2003 level unless otherwise noted.
 - PPL EU Share of the Network Transmission Service Peak Load Responsibility in the PPL Zone time the Monthly Carrying Charges of the Zone Reactive Supply Units as specified in the OATT Schedule 2
 - PJM System Control, and Dispatch Service (OATT Schedule 1) are unbundled in (Schedule 9). It include Control Area , Capacity Adequacy, Market Support, Regulation and Frequency Response, Internal Energy Transaction, and Capacity Resource and Obligation Administration. These charges are based on the PJM projected rates including the Transmission Market Expansion Charges for Commonwealth Edison joining PJM.
 - OATT Schedules effective for 2004
 - Rate approved by FERC in the OATT effective in 2002.
 - PJM West Transition Charge as currently defined for Allegheny Electric is to end when Transitional Market Expansion Charge (Schedule 11) and the Revenue Neutrality Charges (Schedules 7, 8) equal \$84,993,360. This is anticipated to occur near the end of 2004.
 - Market Based Pricing
 - If Commonwealth Edison Joins PJM in November of 2003 the Transmission Market Expansion Charges PPL would incur are projected to be approximately equal to the reduction in Schedule 9 charges resulting in a net zero effect on PPL EU.

Relative Transmission Rates

2004 Forecast Loads

Peak Load Responsibilities based on 2003 Winter Peak

	Rate (\$/KWH)	Deviation from Avg.
IST	\$0.00389	(\$0.00169)
LP6	\$0.00393	(\$0.00165)
LP5	\$0.00455	(\$0.00103)
ISP	\$0.00456	(\$0.00102)
LP4	\$0.00459	(\$0.00099)
GS3	\$0.00470	(\$0.00088)
LPEP	\$0.00490	(\$0.00068)
ISM	\$0.00492	(\$0.00066)
GS1	\$0.00541	(\$0.00017)
STL	\$0.00604	\$0.00046
IS1	\$0.00667	\$0.00109
GRS, EXR, BL	\$0.00712	\$0.00154
GH	\$0.00765	\$0.00207
RTS	\$0.01097	\$0.00539
Total	\$0.00558	
Industrial	\$0.00445	(\$0.00113)
Commercial	\$0.00495	(\$0.00063)
Residential	\$0.00723	\$0.00166

Relative Transmission Rates

2003 Loads

Peak Load Responsibilities based on 2002 Summer Peak

	Rate (\$/KWH)	Deviation from Avg.
STL	\$0.00161	(\$0.00423)
LPEP	\$0.00205	(\$0.00379)
IS1	\$0.00336	(\$0.00248)
ISM	\$0.00360	(\$0.00223)
RTS	\$0.00421	(\$0.00163)
IST	\$0.00441	(\$0.00143)
LP5	\$0.00533	(\$0.00051)
LP4	\$0.00538	(\$0.00046)
ISP	\$0.00541	(\$0.00043)
LP6	\$0.00553	(\$0.00031)
GH	\$0.00590	\$0.00006
GRS, EXR, BL	\$0.00597	\$0.00013
GS3	\$0.00640	\$0.00056
GS1	\$0.00727	\$0.00144
Total	\$0.00584	
Industrial	\$0.00517	(\$0.00067)
Residential	\$0.00591	\$0.00008
Commercial	\$0.00649	\$0.00065

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AUG 24 2004

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU
BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

DOCKETED
AUG 25 2004

PPL Electric Utilities Corporation

Statement No. 5-R

Rebuttal Testimony of Joseph M. Kleha

1 **Rebuttal Testimony of Joseph M. Kleha**

2 Q. Please state your name and business address.

3 A. My name is Joseph M. Kleha. My business address is PPL Services
4 Corporation, Two North Ninth Street, Allentown, Pennsylvania, 18101.

5
6 Q. Did you previously submit direct testimony in this proceeding on behalf of PPL
7 Electric Utilities Corporation?

8 A. Yes. I submitted my direct testimony, Statement No. 5, on March 29, 2004.

9
10 Q. What is the purpose of your rebuttal testimony?

11 A. My rebuttal testimony responds to the assertions of witnesses on behalf of the
12 various intervenors on the following topics:

- 13 (1) the appropriate cost allocation methodology to be used in this proceeding,
14 including alternatives to PPL Electric's preferred maximum NCP demand
15 allocation method (responding to Mr. Galligan);
- 16 (2) the use of the minimum size system study to determine the applicable
17 customer cost component (responding to Messrs. Galligan and Knecht);
- 18 (3) the exclusion of one-half of future test year plant additions from rate base
19 (responding to Mr. Prisco);
- 20 (4) a reduction in cash working capital due to a change in net lag days
21 (responding to Messrs. Weakley and Morgan);
- 22 (5) the exclusion from rate base of prepaid postage (responding to Mr.
23 Morgan);

- 1 (6) an increase in customer deposits to reflect growth from 2003 to 2004
2 (responding to Mr. Morgan);
- 3 (7) the inclusion of unbilled revenue in future test year operating revenue
4 (responding to Mr. Prisco);
- 5 (8) the calculation of future test year capital stock tax expense (responding to
6 Messrs. Weakley and Morgan);
- 7 (9) the allocation of uncollectible accounts expense to energy and capacity
8 rates (responding to Mr. McCormick); and
- 9 (10) the consideration of generation-related property tax appeals in this
10 proceeding (responding to Mr. Epstein).

11

12 I. Cost Allocation Principles and the NCP Demand Allocation Methodology

13 Q. Mr. Kleha, do you have any general comments regarding the various cost
14 allocation proposals made by other parties in this proceeding?

15 A. Yes. First, when considering the appropriateness of a utility's proposed cost
16 allocation methodology, cost allocation must be recognized for what it is – an art,
17 not an exact science. There is no single, absolutely correct method. Moreover,
18 as the Commission has repeatedly recognized, a cost allocation study serves
19 only as a guide and is just one of several important factors to be considered
20 when designing a utility's rates.

21 Second, other parties in this proceeding offer a variety of criticisms of PPL
22 Electric's cost allocation study. The one consistency among them, however, is
23 that they all propose changes which, if adopted, would place their respective

1 clients in a more advantageous position. The Company, however, lacks the
2 incentive to favor one customer class over another when assigning costs. PPL
3 Electric has attempted to take a reasonable middle-of-the-road position regarding
4 the allocation of costs to the various customer classes. Of particular note is the
5 fact that the Office of Trial Staff, the only other party not associated with a
6 particular customer class, has not challenged or criticized the Company's cost
7 allocation study.

8 Third, consistency is an important factor in cost allocation. There are
9 obviously many different methods of cost allocation, but PPL Electric has used
10 the same approach for many years, and that approach has been consistently
11 approved by the Commission in prior PPL Electric rate proceedings. Changing
12 methods, without a compelling reason, is not appropriate in my opinion.

13 Fourth, a significant change in methodology in this case would be
14 particularly inappropriate. PPL Electric's current rate structure is a product of the
15 rate unbundling process which occurred in its electric restructuring proceeding.
16 The unbundling of rates in that proceeding was based on the cost allocation
17 study from PPL Electric's 1995 base rate proceeding which reflects the
18 Company's operation as a vertically integrated electric company. Thus, PPL
19 Electric's current rate structure contains vestiges of its prior vertical integration.
20 The rate cap on PPL Electric's transmission and distribution rates ends on
21 December 31, 2004, but the cap on generation rates extends through 2009. It
22 would be inappropriate, in my view, to undertake a major revision to PPL

1 Electric's cost allocation procedures in these circumstances. Any such review
2 should await the expiration of the cap on generation rates.

3 Finally, although the opposing parties have raised some interesting
4 theoretical issues regarding cost allocation techniques, those issues have only
5 limited relevance in this proceeding. The central issue to be considered is
6 whether PPL Electric's proposed allocation of the revenue increase and its rate
7 design are reasonable.

8 9 II. Demand Allocation Methodology

10 Q. Please describe PPL Electric's allocation of the costs associated with its
11 distribution-related facilities.

12 A. PPL Electric's allocation of the costs associated with its distribution-related
13 facilities generally adheres to the guidelines set forth in the *NARUC Electric*
14 *Utility Cost Allocation Manual*. The *NARUC Manual* states that an electric utility's
15 distribution-related facilities are, from a design and operational basis, sized to
16 meet the maximum load (demand) requirements of customers. As a result, PPL
17 Electric believes that the maximum non-coincident peak ("NCP") demand
18 allocation methodology is the most appropriate method for allocating the costs of
19 its distribution-related facilities. It should be noted that PPL Electric historically
20 has used, and this Commission has accepted, the use of the maximum NCP
21 demand method to allocate the costs associated with the distribution-related
22 facilities reflected in all of its previous base rate cases.

1 Q. Do you agree with Mr. Galligan's proposed use of a peak and average demand
2 allocation methodology to allocate the costs associated with distribution-related
3 facilities?

4 A. No, I do not. The use of the peak and average demand allocation method would
5 allocate the costs associated with distribution-related facilities partially on the
6 basis of the load (demand) imposed on the distribution system by customers, and
7 partially on the basis of energy consumed by customers. The allocation of the
8 costs associated with distribution-related facilities in this manner is inappropriate
9 for the following two reasons.

10 First, as the NARUC Manual succinctly states, there is no energy
11 component of distribution-related facilities (and expenses), only the demand and
12 customer components.

13 Second, distribution facilities do not vary based on the amount of energy
14 consumed by customers, rather, distribution facilities are sized to meet the peak
15 load (demand) requirements of customers, and increase in size only when the
16 peak load requirements imposed on those facilities outgrows the capability of the
17 facilities.

18 As a result, the peak and average method does not, in my opinion,
19 properly recognize cost causation when it is used to allocate the costs associated
20 with an electric utility's distribution-related facilities.

21

1 III. Use of a Minimum Size System Study

2 Q. Have you reviewed Mr. Galligan's criticism of PPL Electric's use of a minimum
3 size system study to determine those costs to be classified as customer-related?

4 A. Yes, I have. Mr. Galligan criticizes PPL Electric because its minimum size
5 distribution system study is based on the smallest size equipment currently being
6 installed on its system, and because the smallest size of certain individual
7 components of that equipment have changed over time. He also criticizes PPL
8 Electric's method stating that it results in higher cost attribution than would result
9 from using a different method. However, although he apparently supports the
10 use of a "zero intercept" method, he has not offered the results of that method or
11 any other method to support his position.

12
13 Q. Do you agree with this criticism?

14 A. No, I do not. PPL Electric has followed the NARUC Cost Allocation Manual that
15 defines a minimum size distribution system based on the smallest size
16 equipment currently being installed by the utility. As such, it is clearly recognized
17 that the size of individual components of the minimum size system will change as
18 the load imposed by customers on an electric utility's distribution-related facilities
19 increases over time.

20
21 Q. Messrs. Galligan and Knecht suggest that the zero intercept method is better
22 than the minimum size system method. Is this suggestion realistic?

1 A. No. The Company has investigated the use of the zero intercept method and
2 found this method impractical, given the available data in its accounting records.
3 As Messrs. Galligan and Knecht recognize, this method has inherent problems
4 namely the lack of necessary data. Even if the necessary data were available,
5 the zero intercept method is complex and inherently arbitrary. PPL Electric's last
6 review of this method produced negative zero intercept cost results for wood
7 poles, copper conductors and aluminum conductors. Therefore, the zero
8 intercept method obviously is not an accurate or reasonable approach for PPL
9 Electric.

10

11 Q. Have you reviewed Messrs. Galligan and Knecht's proposals regarding
12 adjustment of the Company's demand allocators because its minimum size
13 equipment has some load-carrying capability?

14 A. Yes, I have.

15

16 Q. Do you agree with these proposals?

17 A. No. Both witnesses propose to adjust the Company's demand allocators
18 because the equipment used in its minimum size system study has some load-
19 carrying capability. These proposals are flawed for several reasons.

20 First, a minimum size distribution system, by definition, must have some
21 load-carrying capability. The fact that the Company's minimum system has some
22 load carrying capability provides no basis for rejecting it.

1 Second, demand is a function of the load imposed on an electric utility's
2 system by its customers and this demand, and the allocators derived from it, are
3 unaffected by a "hypothetical" minimum size system study.

4 Third, PPL Electric has allocated its primary voltage-related distribution
5 system costs solely on the basis of demand even though the primary voltage
6 system undoubtedly has a customer-related cost component which could offset
7 any perceived overstatement of the customer-related cost component associated
8 with the secondary voltage-related distribution system.

9 Finally, this Commission rejected a similar proposal in PPL Electric's last
10 base rate proceeding at Docket No. R-00943271.

11
12 Q. Do you have any further comments on the minimum size system issue?

13 A. *My specific critique of the opposing party arguments is set forth above. More*
14 *importantly, the selective criticism offered by these witnesses misses the point.*
15 *All aspects of any cost allocation study are based on judgment. The entire*
16 *purpose of a cost allocation study is to "allocate" costs which cannot be directly*
17 *assigned. Reasonable people can differ as to the basis for allocating all of the*
18 *costs in a cost allocation study. However, it is unfair, in my view, to focus on only*
19 *one aspect of cost allocation, criticize it, and adjust it, without concurrently doing*
20 *the same for all other aspects of the study.*

21 For example, Mr. Galligan extensively critiques PPL Electric's allocation of
22 secondary distribution system costs – contending that the Company has
23 overstated the customer component and understated the demand component.

1 Yet, he ignores the fact that PPL Electric's primary distribution plant costs are
2 allocated 100% on a demand basis and 0% on a customer basis. Valid
3 arguments can be made that some portion of primary distribution system costs
4 should be allocated on a customer basis. In my view, any minor overstatement
5 of the customer cost component of the secondary distribution system under the
6 Company's minimum size system method would be, at least partially, offset by
7 the allocation of all primary distribution system costs on a demand basis. For
8 these reasons, it is my opinion that on an overall basis PPL Electric's allocation
9 of its distribution system costs, both primary and secondary, is both fair and
10 reasonable.

11
12 IV. Future Test Year Plant Additions

13 Q. Have you reviewed Mr. Prisco's testimony regarding the Company's future test
14 year plant in service claim?

15 A. Yes, I have. Mr. Prisco proposes to arbitrarily exclude \$64,684,000 from PPL
16 Electric's future test year plant in service claim on the basis that only one-half the
17 new additions will be used and useful.

18
19 Q. Do you agree with Mr. Prisco's proposed reduction to plant in service?

20 A. Absolutely not. Mr. Prisco's proposal is without merit and should be rejected for
21 the following reasons.

22 First, utility ratemaking in Pennsylvania is based on test year data as of
23 the end of the claimed test year. In this proceeding, the end of the claimed test

1 year is December 31, 2004. As such, all components of rate base are
2 determined as of this date. Operating revenues and expenses are determined
3 for the full 12-month period ending December 31, 2004. Consequently, any rate
4 base additions that are projected to be placed in service on or before the last day
5 of the test year are presumed to be in service during the test year.

6 Second, because the claimed future test year in this proceeding will end
7 on December 31, 2004 and new rates will become effective on January 1, 2005,
8 those prospective rates should be based on fully annualized and normalized test
9 year data, including all plant additions.

10 Finally, the Commission's regulations at Section 69.371(a)(4) permit an
11 electric utility to make a claim for construction work in progress ("CWIP"). This
12 Commission has granted rate base treatment for plant additions included in
13 CWIP, if the facilities associated with that CWIP are expected to be placed in
14 service no later than 6 months after the end of the claimed test year.

15
16 V. Cash Working Capital

17 Q. Have you reviewed Messrs. Weakley's and Morgan's testimony regarding the
18 Company's claim for cash working capital?

19 A. Yes, I have. Messrs. Weakley and Morgan propose to reduce PPL Electric's
20 claim for cash working capital due to an incorrect date assigned to an invoice for
21 the delivery of sulfur hexafluoride gas.

22
23 Q. Do you agree with Messrs. Weakley's and Morgan's proposal?

1 A. Yes, I do. In the lead/lag study prepared by the Company in this proceeding, the
2 invoice for the delivery of sulfur hexafluoride gas was inadvertently assigned a
3 negative 85 days lag, rather than the actual 311 days lag. When the actual lag
4 days are used, the average lag in days between the payment of O&M expenses
5 and the receipt of revenue, as shown on Schedule C-4, page 2, of Exhibit Future
6 1, declines from 13.4 days to 12.9 days. This change in the net lag days reduces
7 PPL Electric's cash working capital claim for its combined T&D operations by
8 \$522,000, or \$389,000, on a PUC-jurisdictional distribution-only operations basis.
9 The effect of this correction to cash working capital is shown on Schedule C-4,
10 pages 1 and 2, of Revised Exhibit Future 1.

11

12 VI. Prepayments

13 Q. Have you reviewed Mr. Morgan's testimony regarding the Company's claim for
14 prepaid postage?

15 A. Yes, I have. Mr. Morgan proposes to exclude prepaid postage from the
16 Company's claimed level of prepayments included in its rate base, because
17 postage expenses also are reflected in the Company's lead/lag study.

18

19 Q. Do you agree with Mr. Morgan's proposal?

20 A. No, I do not. As Mr. Morgan clearly recognizes, PPL Electric is entitled to earn a
21 return on cash outflows (prepayments) prior to the time that the items for which
22 the prepayment was incurred are used and recorded as an O&M expense, but
23 would deny the Company this return because postage expenses also are

1 reflected in its lead/lag study. This proposal is inappropriate because it fails to
2 reflect the fact that the two claims arise from two different time periods. The
3 prepayment claim reflects the difference between the time PPL Electric prepays
4 for postage and records it as an O&M expense. The cash working capital claim
5 for postage reflects the difference between when the Company records postage
6 as an O&M expense and when it recovers revenue from customers for that
7 expense. Consequently, there is no double-recovery of a return on prepaid
8 postage, as Mr. Morgan suggests.

9
10 VII. Customer Deposits

11 Q. Have you reviewed Mr. Morgan's testimony regarding the level of customer
12 deposits reflected in the Company's claimed rate base?

13 A. Yes, I have. Mr. Morgan proposes to increase the level of customer deposits
14 reflected in the Company's claimed rate base. He makes this proposal because
15 the Company did not escalate the level of customer deposits for the 2004 future
16 test year over the amount recorded on its balance sheet at December 31, 2003.
17 Mr. Morgan also proposes a related increase to the interest expense associated
18 with customer deposits.

19
20 Q. Do you agree with Mr. Morgan's proposal?

21 A. Conceptually, I agree with Mr. Morgan's proposal. However, his proposed
22 escalation rate of approximately 32% is excessive. During the period January 1,
23 2004 through June 30, 2004, the level of customer deposits increased by 12.95%

1. over the ending balance at December 31, 2003. Based on this rate of escalation
2 for the first 6 months of 2004, PPL Electric would expect the same rate of growth
3 in customer deposits for the next 6 months of 2004, or an overall annual growth
4 rate of 27.6%. As a result, the level of customer deposits to be reflected in the
5 Company's claimed rate base at December 31, 2004 would be \$20,463,000, or
6 an increase of \$4,424,000. This increase in the level of customer deposits is
7 shown on Schedule C-4, page 1, of Revised Exhibit Future 1. The related
8 increase in interest expense associated with customer deposits of \$57,000 is
9 shown on Schedule D-7 of Revised Exhibit Future 1.

10
11 VIII. Unbilled Revenue

12 Q. Have you reviewed Mr. Prisco's testimony regarding the Company's adjustment
13 to eliminate unbilled revenue from its claimed future test year operating revenue?

14 A. Yes, I have. Mr. Prisco proposes to reverse PPL Electric's adjustment to
15 eliminate unbilled revenue in the amount of \$2,395,000 from its claimed future
16 test year operating revenue. This proposal is based on his belief that the
17 elimination of unbilled revenue creates a mismatch between revenues and
18 expenses.

19
20 Q. Is Mr. Prisco correct regarding the elimination of unbilled revenue?

21 A. No, he is not. To the contrary, his proposal to include unbilled revenue would
22 create the mismatch of revenues and expenses he seeks to avoid.

23

1 Q. Please explain.

2 A. Operating revenue is recorded based on energy deliveries through the end of
3 each calendar month. Unbilled retail revenue results because customers' meters
4 are read and bills are rendered throughout the month, rather than all meters
5 being read at the end of the month. Unbilled revenue is recorded each month
6 throughout the year, and the net amount of unbilled revenue for a calendar year
7 is the difference between the amount for December of the current year and
8 December of the prior year. The difference arises primarily from differences in
9 weather and changes in number of customers or changes in usage by existing
10 customers. In this proceeding, unbilled revenue amounts to \$2,395,000 for the
11 future test year ending December 31, 2004, as shown on Schedule D-3 of Exhibit
12 Future 1.

13 For ratemaking purposes, unbilled revenue must be excluded from the test
14 year level of operating revenue to avoid a double-counting of sales revenue for
15 the test year. This double-count would occur because PPL Electric budgets
16 revenue based on normal weather conditions and annualizes the test year level
17 of revenue derived from sales to customers to account for changes in the number
18 of customers in the test year and changes in customers' usage for the full 12
19 months of the test year. As a result, Mr. Prisco's proposed inclusion of unbilled
20 revenue, in conjunction with PPL Electric sales annualization adjustment, would
21 create an overstatement of future test year operating revenue and a mismatch
22 with test year operating expenses.

23

IX. Capital Stock Tax

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23

Q. Have you reviewed the testimony of Mr. Weakley regarding the Company's claim for capital stock tax expense?

A. Yes, I have.

Q. Do you agree with Mr. Weakley's proposals regarding capital stock tax?

A. No, I do not. Mr. Weakley proposes to modify PPL Electric's claim for capital stock tax expense by: adjusting the net income calculation for the 2004 tax year by excluding net income data for the 2000 tax year, including net income data for the 2005 tax year, and decreasing the capital stock tax rate for 2004 from 6.99 mills to 5.99 mills.

Q. Why does Mr. Weakley exclude the net income data for the 2000 tax year?

A. He excludes net income data for the 2000 tax year because the data includes net income from PPL Electric's former generation operations for the period, January 1 through June 30, 2000. Effective July 1, 2000, all generation assets were transferred to an affiliate company.

Q. Is this exclusion 2000 net income data appropriate?

A. No. Mr. Weakley's proposal to exclude net income data for the 2000 tax year is contrary to the calculation used by the Pennsylvania Department of Revenue ("Revenue") to determine a taxpayer's capital stock tax liability. Pursuant to Sections 602(a) and (b) of the Act of March 4, 1971, P.L. 6 (72 P.S. 7602(a) and

1 (b)), a taxpayer's capital stock tax liability is based on the taxpayer's average net
2 income for the most recent 5 tax years, including the current tax year, divided by
3 the taxpayer's net worth at the end of the current tax year. This calculation is
4 made without regard to whether or not a taxpayer's operations changed in any
5 manner at any time within the 5-year period. As a result, PPL Electric's actual
6 2004 capital stock tax liability will be based on its net income for the 5-year
7 period, 2000 through 2004. Therefore, Mr. Weakley's proposal is inconsistent
8 with the Department of Revenue's calculation of the actual taxes PPL Electric will
9 be required to pay for the 2004 tax year.

10
11 Q. Is it appropriate to include net income data for the 2005 tax year in the
12 calculation of the Company's 2004 capital stock tax liability?

13 A. No, it is not. As I previously discussed, the calculation of a taxpayer's capital
14 stock tax liability is based on the average net income for the most recent 5-year
15 period, including the current tax year. To include, as Mr. Weakley has done, the
16 net income for the 2005 tax year in the calculation of PPL Electric's 2004 capital
17 stock tax liability is inconsistent with the Department of Revenue's calculation of
18 PPL Electric's actual tax liability.

19 Moreover, Mr. Weakley's use of 2005 data causes an error in the
20 calculation of capital stock tax liability at present rates. This error occurs
21 because his capital stock tax data for 2005 includes the effect of the rate
22 increase proposed in this proceeding. It is obviously inappropriate to include the

1 incremental capital stock tax liability caused by the proposed rate increase as
2 part of the determination of the Company's tax liability under present rates.

3 In addition, contrary to Mr. Weakley's assertion that the amount of the rate
4 increase granted by the Commission would be an increase to book net income in
5 the current year (2004), any increase granted by the Commission will become
6 effective on January 1, 2005, and will be reflected in PPL Electric's net income
7 for the 2005 tax year. Moreover, if the Commission were to grant PPL Electric
8 the full amount of its proposed rate increase, the incremental capital stock tax
9 liability using Revenue's calculation would be \$660,000, as shown on Exhibit
10 JMK5, not one-tenth of this amount, as Mr. Weakley suggests.

11 The more appropriate approach, and the one PPL Electric has used,
12 without objection, in all prior rate proceedings, is to first present its tax liability,
13 including capital stock tax liability, at present rates, and then "gross-up" tax
14 expense to reflect the effect of the proposed rate increase. Mr. Weakley's
15 attempt to accomplish both steps in one calculation is confusing, and in this
16 instance, erroneous. It also is inconsistent with PPL Electric's and Mr. Weakley's
17 approach for all other taxes.

18
19 Q. Mr. Weakley proposes to calculate PPL Electric's capital stock tax liability at a
20 rate 5.99 mills, rather than the current 2004 rate of 6.99 mills. Is this
21 appropriate?

22 A. No, it is not. The rate of 5.99 mills is the proposed rate to become effective on
23 January 1, 2005. In its filing, the Company indicated that it would include the

1 difference between the current 2004 rate of 6.99 mills and the proposed 2005
2 rate of 5.99 mills in its State Tax Adjustment Surcharge ("STAS") filing to be
3 made on December 21, 2004. The Company proposes to follow this approach
4 because in each of the two previous years, the Legislature rescinded the
5 proposed capital stock tax rate decrease at some point during the year, and
6 increased the applicable capital stock tax rate retroactively to January 1, 2002
7 and January 1, 2003, respectively. To avoid a potential second increase in
8 customer rates because of a change in the capital stock tax rate at some point
9 during 2005, the Company will include the applicable capital stock tax rate in its
10 STAS mechanism, which was designed specifically for such purposes.

11 Contrary to Mr. Weakley's assertion, this approach will include any
12 reductions in the capital stock tax liability due to changes in the net income and
13 valuation components of the capital stock tax, because the STAS is based on the
14 most recent settlement of the Company's capital stock value.

15
16 Q. Have you reviewed Mr. Morgan's testimony regarding the Company's claim for
17 capital stock tax expense?

18 A. Yes, I have. Mr. Morgan, like Mr. Weakley, proposes to modify PPL Electric's
19 claim for capital stock tax expense by: adjusting the net income calculation for
20 the 2004 tax year by excluding net income data for the 2000 and 2001 tax years,
21 including net income data for the 2005 tax year, and decreasing the capital stock
22 tax rate for 2004 from 6.99 mills to 5.99.

23

1 Q. Do you agree with Mr. Morgan's proposals regarding the calculation of the
2 Company's 2004 capital stock tax expense?

3 A. No, I do not. For all of the reasons I previously discussed with regard to Mr.
4 Weakley's proposals, Mr. Morgan's proposals should be rejected.

5
6 X. Allocation of Uncollectible Accounts Expense to Energy and Capacity Rates

7 Q. Have you reviewed Mr. McCormick's testimony regarding his proposal to allocate
8 the costs of customer service activities, e.g., uncollectible accounts, to
9 generation rates?

10 A. Yes, I have. Mr. McCormick proposes to allocate the costs associated with
11 customer service activities, e.g., uncollectible accounts, to PPL Electric's energy
12 and capacity rates charged to its POLR customers, because, in his opinion,
13 these costs are generation related.

14
15 Q. Do you agree with Mr. McCormick's proposal?

16 A. No, I do not. Mr. McCormick's proposal to allocate the costs associated with
17 customer service activities, e.g., uncollectible accounts, to PPL Electric's energy
18 and capacity rates charged to its POLR customer is inappropriate for the
19 following reasons.

20 First, PPL Electric incurs certain costs, such as, uncollectible accounts, in
21 its role as an electric distribution company ("EDC"). This role includes the
22 provision of POLR service, which includes energy and capacity. As such, it is

1 proper to include the cost of uncollectible accounts in the determination of PPL
2 Electric's distribution function revenue requirements.

3 Second, PPL Electric's rates for energy and capacity (generation supply)
4 were established in its restructuring proceedings at Docket No. R-00973954,
5 based on the Commission's determination of the market price of energy and
6 capacity.

7 Third, the energy and capacity (generation supply) rates, which were
8 unbundled from the transmission and distribution functions in PPL Electric's
9 restructuring proceedings, include no cost component for uncollectible accounts.
10 Rather, uncollectible accounts expense was, and continues to be, reflected in
11 PPL Electric's unbundled distribution function.

12 Fourth, PPL Electric's energy and capacity (generation supply) rates
13 should not be artificially increased by some portion of its uncollectible accounts
14 expense. Rather, the Company's level of uncollectible accounts expense should
15 be recalculated in a distribution base rate proceeding, such as this one, to reflect
16 the then-current level of write-offs associated with uncollectible accounts.

17 Customers shopping for generation supply with an alternative supplier should
18 pay the supplier's generation supply rates which, presumably, would include that
19 supplier's level of uncollectible accounts expense. This level, most likely, will be
20 much lower than that of PPL Electric, because, as an EDC, the Company, unlike
21 an alternative supplier, has an obligation to serve all customers, regardless of
22 their payment habits.

1 generating facilities are included therein. Consequently, Mr. Epstein's proposal
2 on this issue is inappropriate and clearly outside the scope of this proceeding.

3

4 Q. Does this conclude your testimony at this time?

5 A. Yes, it does.

6

PPL Electric Utilities Corporation

Revised Estimate of Customer Deposits
As of December 31, 2004

(Thousands of Dollars)

Rate Base		<u>Increase</u>	
Balance at December 31, 2003	\$16,039		
Balance at June 30, 2004	18,117	\$2,078	12.95%
Estimated Balance at December 31, 2004	20,463	<u>2,346</u>	12.95%
Adjustment to Rate Base		<u>\$4.424</u>	<u>27.60%</u>
<u>O&M Expense</u>			
Estimated Balance of Customer Deposits at December 31, 2004		\$20,463	
Interest Rate		<u>1.28%</u>	
Interest on Customer Deposits		262	
Less: Claimed Amount ¹		<u>205</u>	
Increase in O&M Expense		<u>\$ 57</u>	

¹ Schedule 7 of Exhibit Future 1.

PPL ELECTRIC UTILITIES CORPORATION
Capital Stock Tax at Present Rates
For the Year Ending December 31, 2004
(Thousands of Dollars)

<u>Description</u>	<u>Requested Amount</u>	<u>Adjusted Amount</u>	<u>Increase</u>
Net Income			
2000	\$ 277,364	\$ 277,364	
2001	124,282	124,282	
2002	43,633	43,633	
2003	28,470	28,470	
2004 *	<u>45,551</u>	<u>135,713</u>	
Total	<u>\$ 519,300</u>	<u>\$ 609,462</u>	
Average	<u>\$ 103,860</u>	<u>\$ 121,892</u>	
Net worth at December 31, 2004	<u>\$ 1,287,339</u>	<u>\$ 1,287,339</u>	
PA Capital stock value	\$ 1,029,384	\$ 1,124,289	
Statutory Exemption	<u>125</u>	<u>125</u>	
Value of Capital Stock less Statutory Exemption	1,029,259	1,124,164	
Apportionment Percentage	<u>0.995148</u>	<u>0.995148</u>	
PA Capital Stock Taxable Value	<u>\$ 1,024,265</u>	<u>\$ 1,118,710</u>	
PA Capital Stock Tax at 6.99 mills	<u>\$ 7,160</u>	<u>\$ 7,820</u>	<u>\$ 660</u>

Note: PA Capital Stock Tax=50%((5 Year Average Net Income/.095)+(75%(Net Worth))

* 2004 book income increased and net worth increased by \$90,162 to reflect the effect of base rate increase requested.

DOCUMENT

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S OFFICE
PPE ELECTRIC UTILITIES CORPORATION

Statement No. 6-R

Rebuttal Testimony of Oliver G. Kasper

1 Q. Please state your full name and business address.

2 A. Oliver G. Kasper, Two North Ninth Street, Allentown, PA 18101.

3

4 Q. Have you previously submitted testimony in this proceeding?

5 A. Yes. I submitted my direct testimony (Statement 6) on March 29, 2004.

6

7 Q. Mr. Kasper, what is the purpose of your testimony?

8 A. The purpose of my testimony is to respond to the direct testimony of witnesses on
9 behalf of the Office of Consumer Advocate (Mr. Richard Galligan) and the Office of
10 Trial Staff (Mr. Paul M. Yarolin) regarding the Residential rate designs; to respond to
11 the witnesses for PLUG (Mr. Joseph V. Link and Mr. John E. Bradley) on unmetered
12 service for traffic signals; and to respond to the witness for DOD (Mr. Kenneth L.
13 Kincel) on Tariff Rule 8 – Meter Installations. I also will describe a correction to the
14 Proposed Tariff for Economic and Industrial Development Initiatives Rider.

15

16 **Tariff Rule 8, Section B – Meter Installations**

17

18 Q. DOD witness Mr. Kincel takes exception to the Company's proposed change in
19 Tariff Rule 8 - Measurement of Service. Do you have a comment on his
20 statement?

21 A. Yes. Mr. Kincel does not correctly apply the proposed clarification in Tariff Rule 8.
22 The proposed change will not affect the billing for the Carlisle Barracks. The two
23 meters Mr. Kincel refers to are located within the Carlisle Barracks' substation.

1 PPL considers the substation to be one point of delivery. The clarification in Tariff
2 Rule 8 is intended to address situations in which the meters are not at the same
3 location. In the Carlisle Barracks situation, this clarification would prevent adding
4 two meters together that were installed at different locations on the property.
5

6 **Tariff Rule 8, Section C - Unmetered Service for**

7 **Traffic Signals**

8
9 Q. In his testimony PLUG Witness Mr. Joseph V. Link proposes unmetered service for
10 traffic signals because the electric equipment is "consistent and ascertainable" and
11 the usage can easily be calculated. Do you agree with Mr. Link's comments?

12 A. No, I do not. The electric equipment for traffic signals can be and is varied,
13 including "walk/don't walk" signals, audible pedestrian crossing signals, duplex
14 receptacles and varying number and size of faces on the traffic lights themselves.
15 In addition, the control cabinets for traffic signals can contain varying components;
16 such as heaters, lights, and different arrays of control modules to operate the traffic
17 signal equipment and the sequencing of the equipment at that intersection and, in
18 some instances, to coordinate with traffic signals at other intersections. Also, I do
19 not believe the usage can be reasonably calculated. PPL Electric has in the past
20 looked at the feasibility of unmetered service for traffic signals - most recently
21 during the conversion to AMR meters. Each time we have looked at the potential
22 for unmetered service for traffic signals, we have found it impossible to reasonably

1 estimate the usage. Metered intersections with apparently the same equipment
2 showed differing energy usage.

3
4 An unmetered service for traffic signals would require an initial analysis of all
5 equipment at the location. Thereafter, a process would have to be in place for the
6 customer to notify PPL Electric each time any change in the equipment was made
7 at a location. The billing would then have to be changed accordingly. If a change
8 at a location were inadvertently not reported, then the billing would not reflect the
9 correct usage at that location.

10
11 There are thousands of traffic light locations in PPL Electric's service territory, each
12 location having unique energy consumption patterns. If an unmetered program
13 were put in place, the administration of such a program for the multitude of
14 locations would place an unreasonable burden on PPL Electric and its customers.
15 Each intersection can and does have a variety of differences. The existence of
16 LED lamps is only one of the potential items at any selected street corner. For
17 example, any combination of the following may be found at a typical intersection:

- 18
- 19 Pedestrian control buttons
- 20 Street imbedded traffic sensors
- 21 Duplex receptacles
- 22 Audible signals for the Blind
- 23 Fire Department strobe controls

- 1 Radio receivers/transceivers
- 2 Walk/Don't Walk signals
- 3 Turning Arrow Signal Faces
- 4 Timer Controls (Over night flashing, daytime operation)
- 5 Manual Control Interface board
- 6 Control Box moisture and temperature control
- 7 (Heaters and Fans)
- 8 Cameras with motion sensors

9

10 In addition, the number of light faces or size of lamps behind the faces is variable

11 from intersection to intersection and the sequencing of the fixtures can be varied.

12 Below is typical of what can be found at different traffic light locations within PPL

13 Electric's service territory.

14

Location Number	Number of signal faces	Annual kWh	Annual kWh per signal face
1	24	4,858	202
2	24	5,207	217
3	24	3,107	129
4	18	7,081	393
5	35	8,599	246
6	28	8,399	300
7	24	11,486	479
8	47	9,879	210
9	24	5,230	218
10	18	9,115	506
11	37	7,719	209
12	26	15,520	597
13	61	16,162	265

15

1 Even intersections that appear to have the same equipment (Locations 1, 2, 3, and
2 9) do not have the same annual energy usage. Frankly, there is no consistency on
3 the annual kWh per lamp face that would lead to any reliable estimating
4 procedures for unmetered service for traffic signals.

5
6 Finally, a metered intersection is in the best interest of the customer. As the
7 customers change to LED traffic signals, which according to Mr. Link require less
8 energy, the savings will be directly measured and the anticipated savings will be
9 reflected on their electric bill.

10
11 Q. Mr. Link also proposes a separate unmetered rate schedule for traffic signals. Do
12 you agree with his proposal?

13 A. No, I do not. PPL cannot identify anything unique in the usage characteristics of
14 traffic signals that would support the creation of a separate rate schedule for them.
15 In addition, there are no costs that can be directly assigned to traffic signals that
16 would support a different rate for traffic signals. PPL's objection to an unmetered
17 rate schedule for traffic signals includes my previous comments on unmetered
18 service for traffic signals.

19
20 Q. Mr. Bradley's testimony also proposes unmetered service and a separate rate
21 schedule for traffic signals. Do you have a response?

1 A. His arguments are essentially the same as those presented by Mr. Link. With
2 regard to these proposals, my response to Mr. Link's proposal also applies to Mr.
3 Bradley's testimony.

4.
5 In addition, it should be noted that the only cost difference at a new traffic signal
6 location, between metered and unmetered, would be the cost of the meter base.
7 The meter base is located either on the control cabinet (as an integral part of the
8 control cabinet), or just a few inches away on the service drop leading to the
9 control cabinet.

10 To move to an unmetered tariff for traffic signals from the current metered tariff
11 would require all the customers to remove the existing meter bases and replace
12 them with junction boxes to splice the service wires. Under the current National
13 Electric Code, the meter base cannot be used as a junction box.

14 If only new traffic signal locations were to be unmetered, then a new rate is not
15 justified for the relatively few locations that would be installed in the future.

16
17 **Residential (RS) Rate Design**

18
19 Q. Did you prepare an analysis of the residential rate designs presented in the
20 testimonies of OCA witness Mr. Richard Galligan and OTS witness Mr. Paul M.
21 Yarolin?

1 A. Yes I have. My analysis includes some adjustments that were needed to compare
2 the rate design filed by PPL Electric with those filed by Mr. Galligan and Mr.
3 Yarolin.

4
5 Q. Did you make any adjustments to the rate design suggested by Mr. Galligan for
6 purpose of this comparison?

7 A. No. Mr. Galligan used the same revenue requirement for design of Rate Schedule
8 RS that was filed by PPL Electric. This allowed for a direct comparison between
9 the proposed designs of OCA and PPL Electric.

10
11 Q. Did you make any adjustments to the rate design suggested by Mr. Yarolin for
12 comparison purposes?

13 A. Yes. Mr. Yarolin prepared his rate design based on the OTS recommendation that
14 the proposed increase of \$164,436,766 be reduced to \$73,000,000. In accordance
15 with this recommendation, Mr. Yarolin reduced the residential rate revenue by
16 about \$30.2 million. His rate design includes a customer charge and two kWh rate
17 steps. The rate structure is shown below along with the revenues for each rate
18 component as calculated by Mr. Yarolin.

	<u>Rate</u>	<u>Revenue</u>	<u>Percent of Revenue</u>
Customer Charge	\$8.25/month	\$114,011,964	32.80%
First 800 kWh	\$0.01892/kWh	\$150,771,766	43.38%
All kWh over 800	\$0.01680/kWh	\$82,766,088	23.81%
Totals		<u>\$347,549,818</u>	<u>100.00%</u>

1
2
3
4
5
6

Q. What adjustments did you make to Mr. Yarolin's rate structure?

A. I adjusted Mr. Yarolin's rate components to reflect PPL Electric's requested revenue requirement of \$377,750,000 by maintaining the same percent of revenue for each rate component as suggested by Mr. Yarolin. The results are as follows:

	<u>Rate</u>	<u>Revenue</u>	<u>Percent of Revenue</u>
Customer Charge	\$9.07/month	\$123,890,466	32.80%
First 200 kWh	\$0.02056/kWh	\$53,108,038	14.06%
Next 600 kWh	\$0.02056/kWh	\$110,762,789	29.32%
All other kWh	\$0.01824/kWh	\$89,979,356	23.82%
Totals		<u>\$377,740,649</u>	<u>100.00%</u>

7

Q. Were any other adjustments made?

A. Yes. The revenue total of \$377,740,649 for Mr. Yarolin's rate design was calculated based on the number of bills and kWh in each rate step as shown in Exhibit Regs. § 53.53 Filing Requirement IV-C Attachment 1 page 1. The bill determinants used by Mr. Yarolin were somewhat different from those shown in the referenced document.

14

Q. Why were these adjustments made to the OTS rate design?

A. These adjustments were required to allow the rate structures to be compared directly with PPL Electric and the OCA rate structures. The following table summarizes the three proposed rate designs stated on a comparable basis:

18

1

	<u>PPL</u>	<u>OCA</u>	<u>OTS</u>
Customer Charge	\$12.20/month	\$8.00/month	\$9.07/month
First 200 kWh	\$0.0000/kWh	\$0.02292/kWh	\$0.02056/kWh
Next 600 kWh	\$0.02198/kWh	\$0.02087/kWh	\$0.02056/kWh
All other kWh	\$0.01879/kWh	\$0.01964/kWh	\$0.01824/kWh

2

3 Q. What are the primary objectives of PPL Electric's proposed rate design?

4 A. The rate design proposed by the Company achieved the following objectives:

5

- 6 • To keep the rate increase to most customers in the residential class at 10%
7 or less on a total bill basis,
- 8 • To have zero to 200 kWh usage bills make a larger contribution to recovering
9 fixed costs and
- 10 • To begin the process of moving toward a larger fixed charge and a smaller
11 tail block energy rate.

12

13 Q. Why were these objectives chosen?

14 A. As described in Mr. Krall's Testimony (Statement No. 4), more than 90% of the
15 distribution revenue requirement falls to the residential and commercial customers.
16 However, the Company recognized that it could not simply apply the results of its
17 traditional cost allocation study without a very significant increase to the residential
18 customer classes. Further, PPL Electric wanted to begin taking steps to reduce
19 existing cross-subsidies among customer classes. Through the process of

1 allocating the requested increase as described in Mr. Krall's testimony and
2 applying the rate design described in my testimony, PPL Electric was able to limit
3 the impact of the increase to less than 10% for about 90% of its residential
4 customers.

5
6 Q. Please explain the second rate design objective.

7 A. There are about 180,000 residential bills issued each year by PPL Electric that
8 have zero kWh usage (See Attachment 1). There are another 1.2 million
9 residential bills issued for less than 200 kWh each year. As shown on Attachment
10 2, there is a definite increase in the number of zero usage bills during the winter
11 months, when vacation homes and cabins in the Company's service territory are
12 winterized and closed for 3 to 6 months. In addition, a higher than average
13 percentage of bills with less than 200 kWh usage have service addresses that are
14 different from the billing addresses. Attachment 3 shows the results of a study
15 based on 2002 billing data that compares service and billing addresses by zip
16 code. This study indicates that about 37% of bills for usage of 200 kWh or less per
17 month have a billing address that is different from the service address whereas
18 only about 11% of bills for usage greater than 200 kWh per month have a billing
19 address that is different from the service address. The seasonal pattern of zero
20 kWh usage bills along with the high incidence of these bills with different service
21 and billing addresses indicates that a high percentage of these zero and low-use
22 accounts are vacation homes or cabins.

1 Q. What is the concern with zero usage and low monthly kWh bills?

2 A. The problem is that these low usage customers are not paying their proportionate
3 share of the fixed costs required to serve a typical residential customer. Zero kWh
4 usage bills are billed only the Customer Charge of \$6.47 per month and 200 kWh
5 bills are billed only \$10.06 per month under PPL Electric's current rates. These
6 amounts are not sufficient to recover the basic customer cost component as
7 calculated in the company's cost allocation study for the test year ended
8 December 31, 2004, which is \$21.69/customer per month.

9

10 Q. Does PPL Electric's proposal address this third rate design objective?

11 A. Yes it does. PPL's cost allocation study indicates that for Rate Schedule RS, about
12 80% of the revenue requirement is part of the customer component and the
13 remaining 20% is the demand component. Since most costs are fixed and very
14 little of the revenue requirement is due to demands placed on the distribution
15 system by residential customers, a larger fixed charge is justified.

16

17 Q. Do the residential rate designs offered by Mr. Galligan and Mr. Yarolin achieve all
18 three objectives identified above?

19 A. No, they do not.

20

21 Q. How does the PPL Electric proposal compare with the modified OTS and OCA
22 proposals with regard to keeping the majority of the residential bills below a 10%
23 increase?

1 A. Nearly 90% of the residential bills would receive an increase of less than 10%
 2 under rates proposed by the Company. Under the OCA's proposal, about 65% of
 3 the bills would get an increase of less than 10%. The modified OTS's proposal
 4 would result in an increase of less than 10% for only 40% of the bills.

5

	<u>Bills above a 10% Increase</u>	<u>Bills below a 10% Increase</u>	<u>Percent of Bills Below a 10% Increase</u>
PPL Proposal	1,440,000	12,220,000	90%
OCA Proposal	4,745,000	8,915,000	65%
OTS Proposal	8,165,000	5,495,000	40%

6

7 Q. Do either of the rate designs suggested by OCA or modified OTS address the
 8 subsidy between the large usage bills and small or zero kWh usage bills within the
 9 residential class?

10 A. No. By keeping the customer charge low and not significantly increasing the
 11 amount paid by very low usage customers, both of these rate designs support the
 12 low and zero usage customers by increasing the cost to higher kWh usage
 13 customers.

14

15 **Residential Thermal Storage (RTS)**

16

17 Q. Do you agree with Mr. Galligan that the Customer Charge for Rate Schedule RTS
 18 should be increased by only \$1.45/month, the same as his recommendation for
 19 Rate Schedule RS (Residential Service)?

1 A. No I do not. The fixed costs to serve residential and small commercial customers
2 (Rate Schedule GS1) are similar. As stated above, the current Customer Charge
3 does not recover all fixed costs associated with serving a residential customer and
4 therefore a significant increase in the Customer Charge is justified. In addition, the
5 Company tried to maintain the existing relationships between rate options. For
6 example, the current off peak water heating - single meter (rate provision RW1)
7 Customer Charge of \$12.61 is a combination of the Rate Schedule RS Customer
8 Charge of \$6.55 and the off peak water heating – separate meter (rate provision
9 RWO) Customer Charge of \$6.07. (The one-cent difference is due to rounding
10 when STAS is applied). The Company proposed customer charges of \$20.20 for
11 rate provision RW1 which is the sum of the proposed \$12.20 customer charge for
12 Rate Schedule RS, and the proposed \$8.00 customer charge for rate provision
13 RWO. The Company recommends maintaining the existing rate relationships and
14 employing gradualism to reduce cross subsidies over time.

15
16 Q. Do you agree with Mr. Yarolin that the rate of return for Rate Schedule RTS should
17 be increased from -3.95% as filed to 0%?

18 A. No, I do not. The increase needed to make this happen is simply too large (18% in
19 total) and would compromise the Company's objective of keeping the increase for
20 the majority of customers at less than 10% in this rate case. The Company agrees
21 that this rate schedule is producing insufficient revenues and will seek to rectify this
22 disparity over time.

23

1 **Rate Schedules GS1 and GS3**

2

3 Q. What comments do you have regarding rates charged to non-profit organizations
4 under Rate Schedules GS1 and GS3.

5 A. Rates for non-profit organizations that are served under Rate Schedules GS1 and
6 GS3 will have distribution rates that are identical to the rates established for Rate
7 Schedule RS.

8

9

Street Lighting

10

11 Q In his testimony PLUG Witness Bradley makes several comments on what he
12 perceives as problems with PPL Electric's maintenance of the street lights in
13 Hampden Township. Do you have any response to his comments?

14 A. Yes. For all types of street lighting, PPL Electric relies upon local police and the
15 public to report service interruptions. With 170,000 outdoor lights to operate and
16 maintain, maintaining a staff to continually patrol outdoor lights is cost prohibitive.
17 A call from the local police or the public is much more effective.

18

19 Once a malfunctioning light is reported, the Company has a program under which it
20 endeavors to repair 90% of the reported lights within 3 workdays. Of course, there
21 will be a small number of lights that go un-repaired for longer than 3 workdays.

22 The reasons for the delay can include availability of crews, material shortages,

23 need to order replacement parts, weather-related work, etc.

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PPL Electric has reviewed its street lighting maintenance program. We reaffirm our commitment to repair 90% of the reported malfunctioning lights within 3 workdays of the report. The Company's customer support personnel have a heightened awareness of the need to respond to reports of malfunctioning streetlights.

Q. How has PPL Electric changed its streetlighting maintenance program?

Q. In the past, PPL Electric had a group relamping program (up until December 2000). At that time, PPL Electric changed to a program of spot replacements as failures occurred to take advantage of the lamp's full service life. When PPL Electric would receive a notice of a streetlight out of service, the Company would assign the repair to a line crew that was scheduled to be in the area of the reported outage. If a crew was not scheduled in the area, the lamp may have remained out of service for longer than 3 days.

The Company received a number of complaints about streetlights that were out for extended periods of time (longer than 3 days) with this work process. In 2002, the Company reviewed the existing process of spot replacements and decided to restart the group relamping program.

Q. What is group relamping?

A. Group relamping is a process by which all street light lamp bulbs in a defined geographic area are replaced on a regularly scheduled basis. Under this process,

1 the majority of bulbs in a group are replaced before they burn out instead of being
2 replaced individually as they fail. The program design is based upon the rated life
3 of the lamps. At PPL Electric, the group relamping program involves changing
4 mercury vapor and high-pressure sodium lamps on a 6-year cycle.

5
6 Q. When did PPL institute the program?

7 A. PPL Electric restarted the program in December 2002. Along with this program,
8 PPL set a goal of replacing 90% of reported spot outages in 3 days.

9
10 Q. Are there additional costs with a group relamping program?

11 A. In the short term, yes, because lamps that haven't failed are being replaced in
12 addition to replacements of all lamps that fail. In the long term, with an economic
13 replacement cycle, travel, search and diagnostic time savings exceed the loss of
14 remaining service life.

15
16 Q. Do you believe that providing feed back to customers on individual lamp outages is
17 reasonable?

18 A. With regard to his comment on the need for feedback from PPL on reported
19 outages, it is not practical to provide feedback to each and every outage report with
20 170,000 outdoor lights to monitor.

21
22 Q. Mr. Bradley suggests that outage credits be given for street lights that are out for a
23 period of time longer than the 3 days. What is your opinion on outage credits?

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A. PPL Electric's maintenance program includes group re-lamping for all those street lights that PPL Electric is responsible to maintain, which reduces the occurrence of spot failures. The program also includes a goal to restore service to those street lights for which PPL Electric provides maintenance within 3 workdays, after they are reported out of service by customers. With this program in place, the value of outage credits is outweighed by the cost to administer them. In my opinion, global outage credits are not an efficient way of dealing with those relatively few situations in which a light is out for an extended period.

**Tariff Correction for
Economic and Industrial Development Initiatives Rider**

Q. What are the corrections that are being submitted with your rebuttal testimony with regard to the Proposed Economic Development Initiatives (EDI)/Industrial Development Initiatives (IDI) Rider?

A. As noted in the Proposed Changes Requested in Supplement No. 38 to Tariff Pa. P.U.C. #201, and as described in my direct testimony, the Company has proposed to eliminate the EDI and IDI Rider credits for Distribution Service. Credits for Basic Utility Supply Service (energy and capacity) will continue until the generation rate caps expire at the end of 2009. Under this proposal, the total EDI/IDI credits for an existing customer purchasing Basic Utility Supply Service from PPL Electric will be as follows:

Rate Schedule	GS-3	LP-4	LP-5
Demand	\$1.73/kW	\$1.86/kW	\$1.98/kW
Energy	\$0.0086/kWh	\$0.0093/kWh	\$0.0099/kWh

1

2

The total EDI/IDI credits for a new customer purchasing Basic Utility Supply

3

Service from PPL Electric will be as follows:

4

Rate Schedule	GS-3	LP-4	LP-5
Energy	\$0.0086/kWh	\$0.0093/kWh	\$0.0099/kWh

5

6

These changes will be reflected in the compliance filing.

7

8 Q. Does that conclude your testimony?

9 A. Yes, it does.

10

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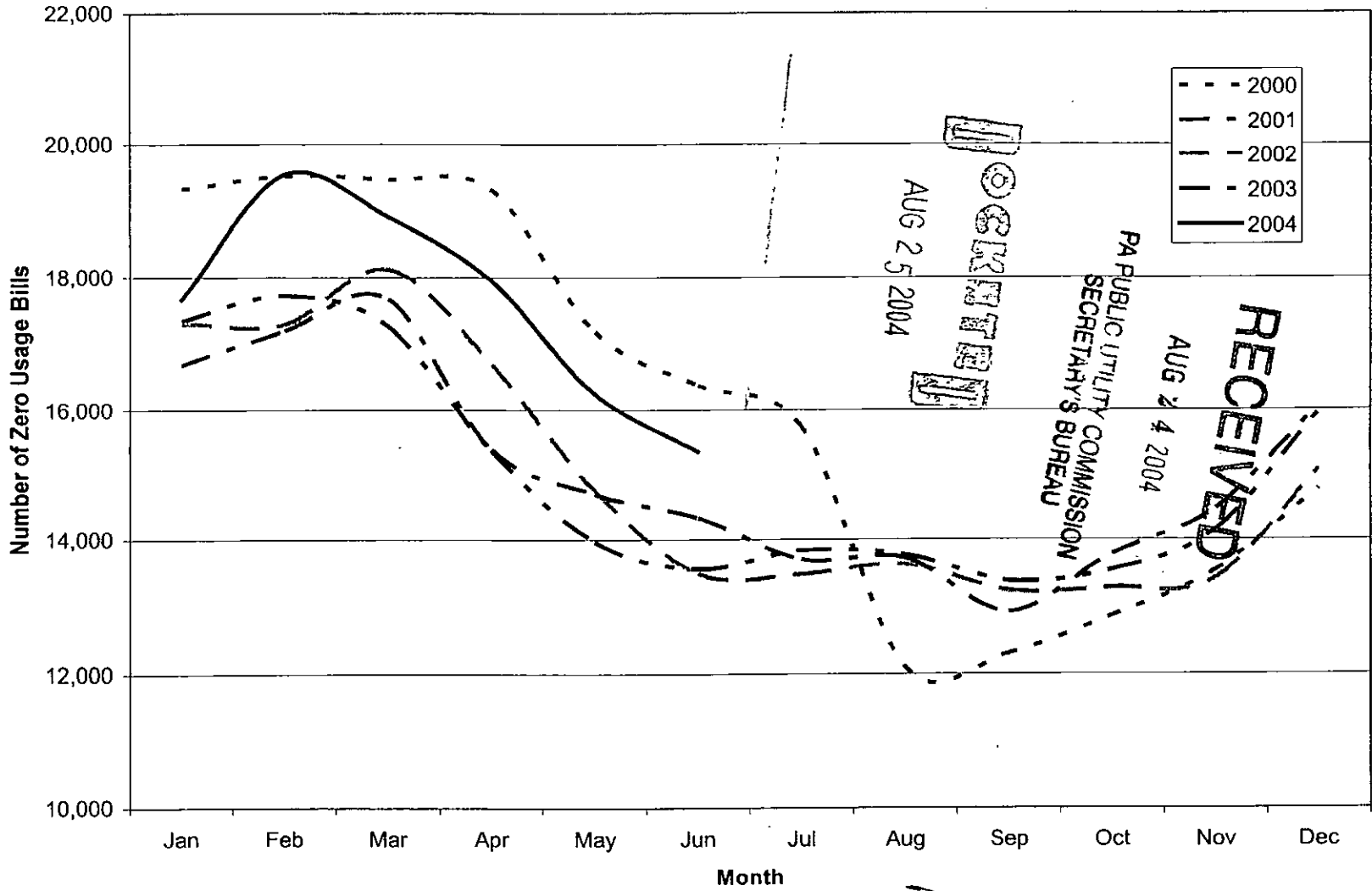
KWh step	Number of Bills		Bills Share	
	Total Residential		Total Residential	
			% of Total Residential	Cumulative Percent
0	176,959		1.31%	1.31%
25	159,195		1.18%	2.48%
50	105,467		0.78%	3.26%
75	112,672		0.83%	4.10%
100	126,928		0.94%	5.03%
150	324,190		2.40%	7.43%
200	413,991		3.06%	10.49%
250	476,115		3.52%	14.01%
300	525,707		3.88%	17.89%
350	555,634		4.11%	22.00%
400	574,575		4.25%	26.24%
450	581,321		4.30%	30.54%
500	573,524		4.24%	34.78%
550	561,654		4.15%	38.93%
600	542,766		4.01%	42.94%
650	517,234		3.82%	46.76%
700	493,480		3.65%	50.41%
750	465,081		3.44%	53.84%
800	436,841		3.23%	57.07%
850	406,932		3.01%	60.08%
900	380,723		2.81%	62.89%
950	352,921		2.61%	65.50%
1,000	328,186		2.43%	67.92%
1,050	303,798		2.24%	70.17%
1,100	281,839		2.08%	72.25%
1,150	260,460		1.92%	74.18%
Over 1,150	3,494,743		25.82%	100.00%
TOTAL	13,532,936		100.00%	

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Zero Usage Bills



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ALL Residential Bills

KWH Step	ALL Residential Bills			Percent of Two Zip Code Bills
	Total	One Zip Code	Two Zip Code	
0	176,959	76,485	100,474	
25	159,195	83,772	75,423	
50	105,467	56,280	49,187	
75	112,672	63,633	49,039	
100	126,928	78,109	48,819	
150	324,190	225,199	98,991	
200	413,991	315,563	98,428	
Totals	1,419,402	899,041	520,361	

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250	476,115	382,895	93,220
300	525,707	437,795	87,912
350	555,634	473,559	82,075
400	574,575	497,318	77,257
450	581,321	508,453	72,868
500	573,524	506,208	67,316
550	561,654	498,100	63,554
600	542,766	483,236	59,530
650	517,234	462,234	55,000
700	493,480	442,349	51,131
750	465,081	417,542	47,539
800	436,841	392,890	43,951
850	406,932	365,943	40,989
900	380,723	342,439	38,284
950	352,921	317,665	35,256
1,000	328,186	295,895	32,291
1,050	303,798	274,125	29,673
1,100	281,839	253,985	27,854
1,150	260,460	234,837	25,623

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**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00049255

DOCKETED

AUG 25 2004

PPL Electric Utilities Corporation

Statement No. 7-R

Rebuttal Testimony of Timothy R. Dahl

1 **Rebuttal Testimony of Timothy R. Dahl**

2 Q. Please state your full name and business address.

3 A. My name is Timothy R. Dahl and my business address is PPL Electric Utilities,
4 827 Hausman Road, Allentown, PA 18104.

5
6 Q. What is your position at PPL Electric Utilities (“PPL Electric” or “Company”)?

7 A. I am the Manager – Regulatory Programs & Business Services in PPL Electric’s
8 Customer Services Department. I report directly to the Vice President –
9 Customer Services.

10

11 Q. What are your major responsibilities?

12 A. My responsibilities include oversight of the Company’s universal service
13 programs, quality assurance and compliance with PUC Chapter 56 regulations
14 and the Customer Choice program. I serve as PPL Electric’s liaison with various
15 state agencies (e.g., Commission’s Bureau of Consumer Services) regarding
16 these three areas of responsibility.

17

18 Q. What is the purpose of your rebuttal testimony regarding PPL Electric’s request
19 for increased rates?

20 A. My purpose is to respond to various witnesses’ proposals and concerns
21 regarding the Company’s universal service programs, Sustainable Energy Fund
22 (“SEF”) and the Community Betterment Initiative (“CBI”).

23

1 Q. In general terms, could you please summarize the key recommendations
2 identified by the various witnesses?

3 A. Yes, I will. Several witnesses offered suggestions and comments regarding
4 PPL's major universal service programs, which include the Company's OnTrack
5 payment program (known generically as a Customer Assistance Program or
6 "CAP"), the free weatherization program (Winter Relief Assistance Program or
7 "WRAP") and the Operation HELP hardship fund.

8
9 I. Summary of Recommendations

10 Q. In summary, what are the key recommendations offered by witnesses regarding
11 PPL Electric's universal service programs?

12 A. **OnTrack:** Witnesses Eugene Brady and John Howat (Commission on Economic
13 Opportunity or "CEO") and Roger Colton (Office of Consumer Advocate or
14 "OCA") all contend that the program is not appropriately funded. Although
15 neither witnesses Brady nor Howat provides a recommended level of funding for
16 OnTrack, they suggest participation levels of 50 percent and 35 percent,
17 respectively, for low-income customers. Similarly, Mr. Colton does not offer a
18 specific level of annual funding for OnTrack; instead, he recommends that PPL
19 Electric unilaterally impose a payment plan for all confirmed low-income
20 customers who are in arrears and not on payment plans. Witness Colton
21 suggests that the Company conduct a pilot program to help low-income
22 customers in arrears to file for and receive the federal Earned Income Tax Credit.
23 In theory, customers would use these additional dollars to pay their overdue
24 balances for electric service. Both witnesses Howat and Colton contend that

1 PPL Electric must conduct more outreach for the OnTrack payment program.
2 Witnesses Brady, Howat and Colton recommend that the Company eliminate the
3 payment-trouble requirement of OnTrack and open the program to a much larger
4 population of low-income customers.

5 **WRAP:** Mr. Howat recommends increasing the funding level to \$7 million
6 annually for this program, beginning in 2005 and continuing through 2011.

7 Witness Howat suggests that PPL Electric devote \$1 million annually to solar
8 water heating installation for low-income customers during this period of time.

9 PPL Electric has proposed to ramp up expenditures for OnTrack and
10 WRAP over a period three years and to "normalize" costs over a period of six
11 years. Witness Colton recommends that the Company "normalize" these
12 additional costs over a period of two years. Mr. Colton suggests that all
13 customers – not just residential – should pay for PPL Electric's universal service
14 programs. Witness Eric Epstein suggests that PPL Corporation use shareholder
15 funding to match the annual funding levels for both OnTrack and WRAP.

16 **Operation HELP:** Witness Colton recommends that PPL Electric file a
17 plan with the Commission's Bureau of Consumer Services to increase donations
18 to Operation HELP by 20 percent. Under Mr. Colton's proposal, the Company
19 would submit this plan within 90 days of the disposition of the rate case. Witness
20 Colton also suggests that PPL Corporation increase its annual shareholder
21 contributions to Operation HELP. Witness Epstein recommends that the
22 Company should use shareholders' funds to match ratepayers' contributions to
23 Operation HELP.

1
2 Q. What were the major recommendations offered by the various witnesses
3 regarding the Sustainable Energy Fund ("SEF" or "Fund")?
4 A. The recommendations regarding the SEF vary widely from eliminating all funding
5 entirely to doubling the amount of annual funding to allocating 36 percent of all
6 funding to residential customers to turning over the administration of the Fund to
7 the Pennsylvania Energy Development Authority ("PEDA"). Witnesses Thomas
8 Prisco (Department of the Army), Stephen Baron (PPL Industrial Customer
9 Alliance) and Michael Gruber (PUC's Office of Trial Staff) recommend the
10 elimination of all ratepayer funding for the SEF. Witnesses Brady and Howat
11 suggest allocating the 36 percent of SEF funding collected from the residential
12 class to a grant program to install photovoltaic units for residential customers,
13 including low-income households. Witness John Hanger (PennFuture)
14 recommends increasing the funding level for SEF from .01 cents per kWh to .02
15 cents per kWh. Mr. Hanger further states that neither the Company's 1998
16 Settlement Agreement or any Commission Order requires the expiration of
17 funding from PPL Electric's customers for the SEF. Witness Andrew Schwarz
18 (Office of Small Business Advocate) recommends that PPL Electric turn over the
19 management of the SEF to PEDA to ensure better coordination of funding and
20 more effective accountability. Witnesses Joseph Link, Michael Musser and John
21 Bradley (Public Lighting User Group or "PLUG") note that PLUG plans to explore
22 the availability of grants from the SEF. Mr. Link recommends that the
23 Commission set standards for the implementation of the Fund and, in particular,

1 compensation for the SEF's Board of Directors.

2

3 Q. What were the primary recommendations regarding PPL Electric's proposal to
4 implement the Community Betterment Initiative ("CBI")?

5 A. Witnesses Colton and Howat both indicated their support for the CBI, but Mr.
6 Howat recommended the implementation of a formal review process for grants
7 that includes the involvement of community-based organizations. Although not
8 opposed to the objectives of the program, Witnesses Prisco and Weakley
9 recommend no funding from ratepayers for the CBI. Witness Epstein suggested
10 that PPL Electric match ratepayer funding for the CBI with funding from
11 shareholders.

12

13 II. Summary of PPL Electric's Concerns

14 Q. Would you summarize, in general terms, PPL Electric's major concerns with the
15 recommendations and issues identified by the various witnesses regarding the
16 universal service programs, the Sustainable Energy Fund and the Community
17 Betterment Initiative?

18 A. **Universal Service Programs:** With respect to the recommendations offered by
19 the witnesses, the Company takes exception to the following:

- 20 1. **OnTrack not adequately funded and available** -- PPL Electric disagrees
21 with this conclusion. The Company's Settlement Agreement clearly
22 delineated the annual funding level for OnTrack, and PPL Electric has
23 managed the program to meet those expenditure requirements. The
24 opposing parties fail to address the fundamental purpose of OnTrack, which

1 is to assist low-income, payment-troubled customers (i.e., overdue balances
2 and poor payment histories). A dramatic increase in funding would increase
3 rates for all residential customers, including low-income households. PPL
4 Electric has proposed a balanced approach that increases OnTrack funding
5 and also tempers the rate impact on residential customers.

6 2. **More outreach for OnTrack** -- The Company disagrees with this suggestion
7 because ten years of experience with OnTrack shows that there are sufficient
8 referrals to meet the program's expenditure requirements. If needed, PPL
9 Electric has a variety of resources in place to increase referrals to OnTrack.

10 3. **Elimination of overdue balance for OnTrack** -- The Commission's Policy
11 Statement on Customer Assistance Programs clearly indicates that programs
12 like OnTrack should target payment-troubled customers (e.g., overdue
13 balances and poor payment histories). Expanding OnTrack to a much
14 broader low-income audience would increase costs significantly. Even
15 overlooking the implementation logistics and difficulties, it would cost
16 ratepayers approximately \$40 million annually to support an enrollment of
17 40,000 customers in OnTrack as suggested by Witness Howat.

18 4. **Unilateral payment plans** -- PPL Electric believes this "negative" check-off
19 approach would anger customers, result in numerous PUC complaints, affect
20 the level of customer satisfaction and increase costs.

21 5. **Earned Income Tax Credit Pilot** -- The Company believes this proposal is
22 impractical and would be difficult to implement and manage. It would also be
23 duplicative of programs already run by community action agencies. In the

1 end, customers would be free to spend their tax return as they see fit.

2 Nevertheless, PPL Electric would consider conducting a limited pilot.

3 6. **\$1 million for low-income solar water heating** -- The Company disagrees
4 with this suggestion. PPL Electric's experience with its renewable energy
5 pilot revealed the challenges and difficulties of finding suitable locations to
6 install solar water heating units. The Company's recommendation to expend
7 approximately \$600,000 yearly on solar water heating is a more balanced,
8 practical and achievable approach.

9 7. **Outreach plan for Operation HELP** -- PPL Electric believes this
10 recommendation to increase customer funding by 20 percent is impractical for
11 a mature program (started in 1983) like Operation HELP. The Company
12 believes that implementing an aggressive fund-raising campaign may have a
13 negative effect on contributions. Moreover, this is a voluntary program not
14 reflected in customers' rates. The scope and size of Operation HELP are
15 matters for PPL Electric to determine.

16 8. **Low-income programs funding from all customers** -- PPL Electric does
17 not support this proposal. As designed and implemented, the Company
18 believes that the greatest benefits associated with the low-income programs
19 ultimately accrue to residential customers.

20 9. **Revenue adjustments for OnTrack and WRAP** -- The Company disagrees
21 that it has double counted the OnTrack arrearage forgiveness provision. The
22 Company also has concerns about reducing funding for OnTrack and WRAP
23 because there is no guarantee that PPL Electric will file for another base rate

1 increase in two years.

2 **Sustainable Energy Fund (“SEF”)**: Regarding the various recommendations
3 directed toward the SEF, PPL Electric had the following concerns:

- 4 1. **No funding for SEF** -- The Company does not support this position because
5 continuation of the SEF supports public policy objectives regarding the
6 environment, establishes partnerships with government to address
7 environmental needs and promotes the development of renewable energy
8 technologies. All of which the Company believes would be to the overall
9 benefit of all ratepayers.
- 10 2. **Double SEF funding** – PPL Electric disagrees with this proposal to double
11 the annual funding level. The Company believes that funding the SEF at its
12 current level (.01 cents per kWh) is the appropriate amount of support. What
13 happens in other states may not be germane to or appropriate for
14 Pennsylvania. The Company suggests a balanced approach that continues
15 support for the SEF while, at the same time, is cognizant of the cost impact
16 on customers.
- 17 3. **SEF funding for a photovoltaic (“PV”) grant program** -- PPL Electric
18 disagrees with the recommendation to allocate 36 percent of SEF funding for
19 a PV grant program. First, nothing in the 1998 Settlement Agreement
20 earmarks funding for specific classes of customers or for specific activities.
21 Second, the cost effectiveness of PV systems (30-year payback period) is not
22 favorable when compared with solar water heating (7-10 year payback
23 period). Finally, the SEF staff and Board of Directors need the flexibility and

1 the responsibility to invest customer-provided funds in ways that provide the
2 greatest payback and meet the overall mission of the Fund.

3 4. **Source of SEF funding** -- PPL Electric disagrees with the conclusion that
4 shareholders rather than customers are actually funding the SEF. As a result
5 of its 1998 Settlement Agreement, PPL Electric established a tariff that
6 funded the SEF from the distribution charges in each rate schedule at .01
7 cents per kWh (less applicable Gross Receipts Tax) on all kWh delivered to
8 all customers.

9 5. **Administration of the SEF by PEDAs** -- The Company disagrees with the
10 recommendation to have the management of the SEF's funds turned over to
11 PEDAs. From PPL Electric's perspective, the Commission has sufficient
12 oversight capabilities to ensure the proper expenditure of funds, to avoid
13 conflict of interests and to encourage coordination of efforts among the
14 various Sustainable Energy Funds. In addition, the Commission's
15 Pennsylvania Sustainable Energy Board has oversight and coordination
16 responsibilities for the SEFs.

17 **Community Betterment Initiative ("CBI")**: PPL Electric has several concerns
18 with recommendations regarding the proposed implementation of the CBI.

19 1. **No funding for CBI** -- The Company disagrees with this recommendation
20 because a modest investment in the CBI should return solid benefits in terms
21 of leveraging state funds and maximizing the impact of local community and
22 economic development efforts in a variety of areas. Job creation and tax
23 base enhancement meet the needs of many Pennsylvania communities, and

1 survey research of customers and community leaders has consistently shown
2 that economic development is near or at the top of their key priorities.

- 3 2. **CBI formal review process** -- PPL Electric believes that establishing a
4 formal review process with all relevant stakeholders to oversee the allocation
5 of CBI funds would be cumbersome and could result in delays or conflicts of
6 interest since many of the stakeholders are also likely to be applicants. The
7 Company would develop an internal process to evaluate, select and award
8 CBI grants to community organizations. Through the implementation of its
9 successful Community Partnership Program (1995 - 1997), PPL Electric
10 demonstrated its ability to successfully implement a similar grant program.
11 The Company also has years of experience in evaluating proposals and
12 awarding funding for a variety of community and economic development
13 initiatives. A key funding criterion will be compliance with formal community
14 and economic development strategies of municipalities and other local
15 stakeholders such as non-profit development groups, assuring that their
16 thinking is factored into the decision-making process.

17
18 III. PPL Electric's Responses to Recommendations
19 Re: Universal Service Programs

20 Q. Do you have other concerns and issues about the recommendations offered by
21 the various witnesses regarding the universal service programs, the SEF and the
22 CBI?

23 A. Yes, I do. In addition to presenting more detail of PPL Electric's concerns
24 regarding the above recommendations, I will address other subordinate, yet

1 important recommendations presented in the witnesses' testimony.

2

3 Q. Does PPL Electric have specific concerns and comments regarding the
4 recommendations presented by the various witnesses for the universal service
5 programs?

6 A. Yes, I have identified and responded below to those specific concerns regarding
7 OnTrack, WRAP and Operation HELP.

8

9 Q. What are PPL Electric's major issues and concerns regarding the OnTrack
10 payment program?

11 A. Witnesses Brady, Howat and Colton all note a PUC Order dated June 12, 2003,
12 at Docket No. M-00031698, indicating that OnTrack was neither appropriately
13 funded nor available in the Company's service area. This Order approved the
14 Company's three-year (2004 - 2006) Universal Service & Energy Conservation
15 Plan. PPL Electric disagrees with this conclusion. Under the terms of its 1998
16 Settlement Agreement, all parties agreed to an annual funding level of \$11.7
17 million for OnTrack. The parties also agreed that PPL Electric would ramp up
18 expenditures over a four-year period. The maximum funding amount of \$11.7
19 million for OnTrack would remain in effect until the Company requested
20 permission from the Commission to change the annual level of funding. From
21 1999 through 2003, the Settlement Agreement required PPL Electric to expend a
22 total of \$47.3 million for OnTrack. Over this period of five years, the Company
23 expended approximately \$47.6 million, or 101 percent of the required funding.

1 Given the mandatory cap on electric rates, PPL Electric managed OnTrack to
2 stay within the budget approved by all parties to the 1998 Settlement Agreement.
3 PPL Electric recognizes that there is an opportunity to expand OnTrack
4 enrollment and has proposed to increase annual funding for the program by 25.6
5 percent.

6 Witness Howat indicates that one of the reasons for the inappropriate
7 funding of OnTrack is attributable to excessive administrative costs. PPL Electric
8 disputes this conclusion. The following table shows the average administrative
9 cost for OnTrack over the past three years.

10

2001	2002	2003	Average
18.7%	20.8%	14.2%	17.6%

11
12 The Company's overall administrative costs for OnTrack are, according to the
13 Commission's latest *Report on 2002 Universal Service Programs & Collections*
14 *Performance*, significantly below the electric industry average of 38 percent.
15 Through June 2004, PPL Electric has continued to keep the administrative costs
16 for OnTrack below 15 percent.

17 Witnesses Brady and Howat recommend that PPL Electric expand the
18 percentage of low-income customers served by OnTrack to 50 percent and 35
19 percent, respectively. The Company disagrees with this recommendation for two
20 reasons: 1) these penetration percentages would be excessively expensive and
21 2) these penetration percentages are impractical. Mr. Brady identifies from his
22 perspective an eligible population (i.e., at or below 150 percent of the federal
23 poverty level) of 200,250 low-income customers. PPL Electric's average annual

1 cost for an OnTrack customer is \$998 and includes all program costs (e.g.,
2 revenue shortfall, arrearage forgiveness and administration). Under Witness
3 Brady's scenario, the Company would need an annual OnTrack budget of nearly
4 \$100 million (200,250 x 50 percent = 100,125 x \$998). Similarly, Witness Howat
5 identifies an eligible audience of nearly 114,000 low-income customers.
6 Assuming a penetration rate of 35 percent, PPL Electric would need an annual
7 budget of nearly \$40 million for OnTrack (114,000 x 35 percent = 39,900 x \$998).

8 Using broad indicators (e.g., Witness Brady's use of 2000 U.S.
9 Census data) of eligibility for OnTrack are inappropriate. The following factors
10 act as "filters" to reduce customers' participation in the program.

- 11 • Not payment-troubled.
- 12 • Live in master-metered apartments.
- 13 • Referred by PPL Electric to OnTrack but do not participate.
- 14 • Apply and are ineligible for the program.
- 15 • Know about the program but do not apply.

16 Most of PPL Electric's low-income customers (approximately 80 percent) are not
17 payment troubled (i.e., overdue balances and history of missed payments).

18 Commission regulations at 52 Pa. Code § 69.265 (10)(ii)(B) require utilities to
19 evaluate the impacts of low-income programs at no more than six-year intervals.

20 PPL Electric, through a competitive bidding process, selected The RETEC
21 Group, Inc. ("RETEC") from New Haven, CT to conduct the evaluation. RETEC
22 estimated the market of likely OnTrack participants to be approximately 30,000.

23 PPL Electric generally concurs with RETEC's finding.

1 However, as noted above, being eligible for OnTrack does not
2 automatically translate into participation in the program. PPL Electric's records
3 from 2001 through 2003 show a ratio of 1:2 regarding referrals and enrollments
4 in OnTrack. In other words, for every ten customers referred, five customers will
5 eventually enroll in the program. RETEC concluded in its study that slightly more
6 than one in four customers referred to OnTrack fail to respond to contact
7 attempts or are ineligible. Approximately 95 percent of all OnTrack referrals
8 come from the Company's telephone agents who negotiate payment plans.
9 Other referrals come from community-based organizations ("CBOs") that
10 administer programs like OnTrack, WRAP and Operation HELP. The following
11 table shows the ratio of referrals to enrollments over the past three years.

Activity	2001	2002	2003	Total
Referrals	15,830	23,302	35,255	74,387
Enrollments	7,050	13,732	18,471	39,253
Ratio	1:2.2	1:1.7	1:1.9	1:1.9

13
14 Although the estimated population for active enrollment in OnTrack is
15 approximately 30,000 customers, it is unlikely that PPL Electric could reasonably
16 achieve this level of participation. The Company's practical experience with
17 referrals and enrollments over the past three years appears to confirm this
18 conclusion. PPL Electric's proposal to increase funding by 25.6 percent (i.e.,
19 from \$11.7 million to \$14.7 million) would allow the Company to have a range of
20 15,000 to 17,000 customers enrolled in OnTrack. Not only does this level of
21 funding appear to match customers' need for the program, it also would have a
22 manageable impact on the current delivery structure for OnTrack by allowing the

1 CBOs to absorb the additional workload with minimal interruption.

2 In addition to the protections and benefits offered to customers
3 through programs like OnTrack, PPL Electric's philosophy and approach toward
4 credit and collection activities helps low-income households as well. Among the
5 13 jurisdictional electric and gas utilities in Pennsylvania, PPL Electric has the
6 lowest termination rate. According to the Commission's *Report on 2002*
7 *Universal Service Programs & Collections Performance*, the Company's
8 termination rate, as determined by the Bureau of Consumer Services, was 0.68
9 percent. The average for all electric utilities and gas utilities was 1.75 percent
10 and 2.78 percent, respectively. In other words, residential customers at other
11 electric utilities are two and a half times more likely to have their service shut off
12 for non-payment than a PPL Electric residential customer. Customers at the gas
13 companies are four times more likely to have their service terminated for non-
14 payment than a PPL Electric residential customer.

15 Witness Colton recommends that each May PPL Electric should identify
16 all confirmed low-income customers in arrears and not on payment plans and
17 unilaterally impose budget billing payment plan. This so-called "opt-out" payment
18 arrangement would require these customers to contact the Company in order to
19 negotiate a payment plan consistent with the Commission's guidelines. PPL
20 Electric does not support this proposal for the following reasons:

- 21 • It would anger many customers.
- 22 • It would increase the Company's call volume and costs.
- 23 • It would increase complaints to the Commission, which would further

1 increase costs for PPL Electric.

- 2 • It would adversely affect customer satisfaction.
- 3 • It would not be necessary for all customers because they may pay their
- 4 overdue balances (e.g., LIHEAP grant).
- 5 • It would not necessarily guarantee that customers would make
- 6 payments.

7 The Commission's payment arrangement guidelines already encourage utilities
8 to establish budget billing payment plans for low-income customers that include a
9 portion of the arrearage. The Commission further clarified this guideline in a
10 formal complaint case (Mary Frayne v. PECO Energy, at Docket No. C-
11 20029005).

12 Witnesses Howat, Colton and Brady recommend that PPL Electric expand
13 its outreach efforts for OnTrack and eliminate the requirement for income-eligible
14 customers to have an overdue balance of \$150 to qualify for the program. They
15 conclude that the Company is not "proactive" enough in identifying and referring
16 low-income customers to the program and that the \$150 requirement
17 discriminates against low-income customers who forgo necessities to pay their
18 utility bills. PPL Electric disagrees with this characterization of its outreach
19 efforts for OnTrack and its focus on low-income, payment-troubled customers.
20 The Commission's Policy Statement on Customer Assistance Programs ("CAPs")
21 at 52 Pa. Code § 69.261 and § 69.264 clearly states that CAPs should target
22 low-income, payment troubled customers. As such, the Company has directed
23 its OnTrack enrollment efforts at low-income customers with overdue balances

1 and poor payment histories. PPL Electric's objective has been to match
2 customer enrollment levels with available funding resources. As indicated
3 earlier, PPL Electric has been successful in increasing program enrollment while
4 also expending the level of funds agreed to by all parties in the 1998 Settlement
5 Agreement.

6 Opening OnTrack to a much broader audience of low-income customers
7 (e.g., no overdue balance) creates serious concerns regarding the annual
8 funding level, implementation challenges, increased administrative costs,
9 additional technology costs, etc. The Company also believes it is important to
10 keep rates as reasonable as possible for low-income customers. PPL Electric
11 contends this magnitude of expansion is beyond the scope of what the
12 Commission intended in its CAP Policy Statement. The equity issue (i.e., low-
13 income customers not purchasing necessities to pay utility bills) requires a broad-
14 based approach best addressed by the federal and/or state government. This
15 type of far-reaching social issue is outside the purview of electric utilities.

16 Through its normal process of negotiating payment plans, the Company
17 has a sufficient pool of low-income, payment-troubled customers to refer to
18 OnTrack. The Company's phone reps take an active role in referring customers
19 to the program. They explain the eligibility requirements, they send an electronic
20 referral note to the appropriate OnTrack CBO, and they send a letter to the
21 customer to reinforce the benefits of OnTrack. However, if needed, PPL Electric
22 can conduct additional outreach efforts to identify eligible customers. For
23 example, the Company has utilized bill inserts and radio and TV ads to promote

1 OnTrack. The Company has implemented special outbound calling programs
2 after normal weekday work hours or on Saturdays to inform customers about the
3 availability and advantages of OnTrack. PPL Electric's Customer Programs
4 Directors, who have the day-to-day responsibility for OnTrack, also can work
5 through their extensive network of CBOs to increase referrals to the program.
6

7 Q. What other recommendations have the witnesses offered regarding the OnTrack
8 payment program?

9 A. Witness Colton recommends that PPL Electric implement a pilot outreach
10 program to assist low-income customers in applying for and receiving the federal
11 Earned Income Tax Credit ("EITC"). This proposal, although well intended,
12 presents a variety of concerns and challenges, including the following:

- 13 • Performing considerable administrative work (e.g., identifying
14 customers, determining eligibility, explaining EITC requirements and
15 completing EITC forms).
- 16 • Developing and implementing various customer communication efforts
17 (e.g., fact sheets, Q&A brochure, letters, list of tax preparation offices
18 and phone scripts).
- 19 • Handling ongoing customer inquiries and concerns regarding the EITC
20 process.
- 21 • Monitoring, managing and evaluating the pilot.

22 In addition, obtaining an EITC refund is no guarantee that customers would use
23 the funds to pay their utility bills. They could, for instance, use the refund to

1 purchase other necessities (e.g., prescription medicines). Mr. Colton indicates
2 that New Jersey's results from 1994, which obviously is dated information, shows
3 that 25 percent of EITC recipients used part of the refund to pay utility bills. PPL
4 Electric has had a mixed experience with subsidized housing residents who
5 receive utility allowances, but use the funds to purchase other goods rather than
6 pay their electric bills. At the end of the day, customers are free to spend the
7 EITC refund as they see fit.

8 These concerns and issues notwithstanding, PPL Electric would consider
9 developing and implementing a limited pilot to determine the efficacy of
10 promoting the EITC for low-income households. The Company could target
11 selected areas where local social service agencies that administer programs like
12 OnTrack and WRAP also have experience in promoting the EITC. For example,
13 Schuylkill Community Action in Pottsville has effectively administered PPL
14 Electric's low-income programs for many years and has conducted a program to
15 encourage clients to apply for the EITC.

16 Witnesses Brady and Howat contend that the characterization of CBO
17 costs for OnTrack as "administrative" costs is improper. Mr. Brady states that
18 CBO costs are better described as operational or direct service costs. The
19 Commission's Bureau of Consumer Services requires all jurisdictional electric
20 utilities and gas utilities to report CAP costs under three categories: revenue
21 shortfall, arrearage forgiveness and administration. Revenue shortfall is the
22 difference between customers' actual bills and their CAP bills. Arrearage
23 forgiveness is the amount of pre-program arrearage that the utility write-offs

1 when CAP customers meet certain payment criteria. Administration includes all
2 other costs (e.g., salaries and benefits for utility employees, payments to CBOs,
3 computer hardware and software, printing and postage).

4 Witness Colton expressed concern about the accuracy of the OnTrack fact
5 sheet and recommended that the Company revise it to reflect the operation of the
6 program. The current OnTrack fact sheet indicates that PPL Electric may
7 remove customers from the program for not having applied to LIHEAP or for
8 exceeding 110 percent of their historical kWh usage. The Company included this
9 wording in the fact sheet to encourage customers to apply for LIHEAP and to
10 control their kWh usage. Both of these efforts help to improve the cost
11 effectiveness of OnTrack. The Commission's CAP Policy Statement
12 recommends that utilities encourage customers to apply for LIHEAP benefits.
13 The CAP Policy Statement does allow companies the option of imposing a
14 penalty if customers do not apply for LIHEAP and it recommends a kWh limit of
15 110 percent of historical usage. However, to ensure clarity and consistency, PPL
16 Electric agrees to revise its OnTrack fact sheet.

17
18 Q. Do you have any other comments or observations regarding the OnTrack
19 payment program?

20 A. PPL Electric recognizes the importance of OnTrack and has proposed to
21 increase funding for the program. The Company has structured and
22 implemented the program to address the needs of low-income customers while
23 balancing business, financial, regulatory and public policy interests. PPL Electric

1 will continue to help payment-troubled customers achieve self-sufficiency by
2 providing affordable payments and by referring them to other assistance
3 programs. The Company's objectives for OnTrack are clear:

- 4 • Administer a cost-effective program.
- 5 • Provide meaningful services to low-income customers.
- 6 • Expand enrollment in a cost-effective and manageable fashion.
- 7 • Adhere to PUC regulations and reporting requirements.
- 8 • Identify and implement improvements to strengthen the effectiveness
9 of OnTrack.

10
11 Q. What have the witnesses recommended for WRAP?

12 A. Witness Howat recommends an increase in the annual funding level for WRAP to
13 \$7 million with an allocation of \$1 million annually from the total funding for solar
14 water heating. PPL Electric has proposed to continue solar water heating as a
15 standard WRAP measure for customers who meet the various eligibility
16 requirements. However, the Company disagrees with increasing the WRAP
17 budget to \$7 million and allocating \$1 million annually for solar water heating
18 installations. PPL Electric recommends a three-year ramp up in the level of
19 WRAP expenditures and installations for solar water heating. The Company
20 proposes the following:

21

Year	Est. Funding	Est. Installations
2005	\$325,000	65
2006	\$475,000	95
2007	\$600,000	120

1 Q. Does the Company have any concerns or comments regarding Mr. Howat's
2 recommendation?

3 A. Yes, PPL Electric believes that Witness Howat's proposed \$1 million annual
4 budget for solar water heating installations is overly optimistic for the following
5 reasons. First, finding homes that meet the selection criteria (e.g. proper roof
6 orientation, no shade trees, adequate kWh usage and structural integrity of the
7 home) is very challenging. To find the 89 participants for the solar water-heating
8 and PV pilots, the Company and CBOs had to analyze/evaluate nearly 3,600
9 customer locations. Based on the experience with the solar water-heating pilot,
10 the Company believes that approximately two to four percent of WRAP
11 participants' homes are good candidates for solar water heating. Second, the
12 selection process is further complicated by the fact that customers must consent
13 to the installation of the system and must have demonstrated capacities for
14 managing energy use and understanding the system. Third, installing a solar
15 water heating ("SWH") system is time consuming. Results from PPL Electric's
16 pilot show that it takes two qualified workers 2.5 days to complete one
17 installation. Mass production would not necessarily increase efficiency because
18 every home is different; in other words, there is no "cookie cutter" approach to
19 installing SWH units. In addition, training new contractors for SWH is time
20 consuming and expensive. Finally, installing solar water units affects the
21 productivity associated with traditional WRAP jobs. The four qualified
22 community-based organizations ("CBOs") installed most of the SWH and PV
23 units in 2002. PPL Electric struggled to meet its WRAP expenditure goal in 2002

1 partly because of the greater than anticipated drain that the solar water heating
2 and PV pilots had on the CBOs' weatherization personnel.

3
4 Q. Does PPL Electric have any other concerns with Witness Howat's
5 recommendations regarding WRAP?

6 A. Yes, Mr. Howat suggested that there is a pressing need for WRAP contractors to
7 increase their decision-making capabilities regarding the design elements of the
8 program. PPL disagrees with this conclusion for the following reasons. First, the
9 Commission has adequate oversight responsibilities and a lot of experience
10 regarding the Low Income Usage Reduction Program ("LIURP"). WRAP is PPL
11 Electric's LIURP program. With respect to LIURP, the Commission has
12 promulgated regulations, developed a codebook, established reporting
13 requirements and conducted periodic meetings to discuss LIURP developments
14 and changes. Commission regulations also required that an independent, third
15 party evaluate utilities universal service programs, including LIURP, at least
16 every six years.

17 Second, most utilities, including PPL Electric, work closely with their
18 weatherization contractors regarding the ongoing implementation of the program
19 and the introduction of new features. For example, PPL Electric has collaborated
20 with its WRAP contractors regarding energy conservation education,
21 weatherization standards and benchmarks, various pilots (e.g., baseboard
22 replacement, air conditioning and horizontal axis washing machine), field
23 standards and training. In addition, the Company meets regularly with WRAP

1 contractors to discuss kWh savings results, program results and policy issues
2 and conducts an annual meeting for all WRAP contractors.

3 Finally, WRAP is a mature program and has been providing
4 weatherization services to low-income families since 1985. There have not been
5 that many revolutionary changes regarding the measures and technology
6 associated with the fundamentals of providing weatherization services. With
7 respect to the changes that have occurred (e.g., blower-door testing, combustion
8 testing and mold/mildew problems), PPL Electric and the WRAP contractors
9 have kept abreast of these developments. In addition to providing specialized
10 training when needed, PPL Electric sends its personnel and WRAP contractors
11 to a well-respected national meeting (Affordable Comfort Conference) to learn
12 about recent trends or developments regarding weatherization techniques,
13 technology and evaluation.

14
15 Q. Has PPL Electric identified any other issues or concerns regarding either
16 OnTrack or WRAP?

17 A. Yes, Witness Colton recommends that funding for universal service programs
18 come from all classes of customers and not just the residential class. Mr. Colton
19 also suggests that PPL Electric should normalize OnTrack costs over a period of
20 two years rather than eight years because the Company plans to file for another
21 rate increase. Witness Weakley proposes to "levelize" the OnTrack expense
22 allowance of \$13.2 million for a period of two years. With respect to the first
23 issue, Witness Colton argues that funding for OnTrack is similar to a "public

1 good" in that all classes of customers receive benefits. He suggests that
2 universal service programs increase employee productivity which, in turn,
3 contributes to higher profitability for businesses. Finally, Mr. Colton indicates that
4 it is conceptually wrong to insist that the purpose of OnTrack is to reduce
5 overdue receivables for low-income customers. From his perspective, the issue
6 is whether the program generates benefits for all classes of customers.

7 PPL Electric disagrees with Witness Colton's recommendation regarding
8 funding for the universal service programs. The Company believes it is
9 appropriate only for residential customers to fund OnTrack and WRAP. The
10 Company does not support the conclusion that a low-income program is the
11 equivalent of a "public good." The Commission's CAP Policy Statement (52 Pa.
12 Code § 69.261 and § 69.264) clearly indicates that programs like OnTrack are for
13 low-income, payment-troubled customers. Given the specific and narrow focus
14 of OnTrack, the Company does not believe that the program meets the generally
15 recognized concept of a "public good." Witness Colton's assertion that universal
16 service programs provide benefits to all customers in general and to small
17 business customers in particular is not convincing to PPL Electric. One could
18 argue that keeping electric rates as low as possible for small businesses helps
19 make them more competitive, thereby allowing them to provide jobs to low-
20 income households. Finally, in PPL Electric's 1998 Settlement Agreement, which
21 underwent an exhaustive and thorough evaluation by all parties, they agreed that
22 residential customers were the appropriate source of funding for the universal
23 service programs. The Company believes this rationale still holds true today.

1 Regarding the issue of "normalizing" costs over a period of eight years
2 and the proposal to "levelize" OnTrack costs for two years at an annual funding
3 level of \$13.2 million, the Company disagrees with the recommendations offered,
4 respectively, by Mr. Colton and Mr. Weakley. PPL Electric proposed a
5 normalization period of six years: three years to ramp up expenditures (2005
6 through 2007) and three years (2008 through 2010) to make up for the under
7 expenditures during the ramp-up period. Ramping up expenditures over three
8 years would promote a smoother transition to increased spending and would
9 allow the OnTrack social service agencies to more easily absorb the additional
10 work. The two-year period suggested by Mr. Colton and Mr. Weakley is too short
11 and should not depend on whether PPL Electric files for another rate increase.
12 Even if the Company were to file for another rate increase in two years, all
13 parties would have the opportunity to revisit the three-year ramp-up period and
14 offer recommendations for changes. If the Commission approved Witness
15 Weakley's proposal but PPL Electric did not file for a base rate increase within
16 two years, fewer eligible customers (i.e., approximately 1,500 families annually)
17 would receive OnTrack benefits. PPL Electric recommends a maximum of \$14.7
18 million in annual funding for OnTrack, whereas Mr. Weakley suggests \$13.2
19 million -- a difference of \$1.5 million. At an average annual cost of \$998 per
20 customer, OnTrack would serve less eligible customers under Witness Weakley's
21 proposal (i.e., $\$1,500,000/\$998 = 1,503$ households).

22 Witness Epstein recommends that PPL Corporation should use
23 shareholder funding to match the proposed funding increases for both OnTrack

1 and WRAP. The Company disagrees with this suggestion for several reasons.
2 First, there is nothing in PPL Electric's 1998 Settlement Agreement about
3 requiring funding from shareholders for OnTrack or WRAP. Second, the
4 Commission's regulations regarding universal service programs are silent on
5 shareholder funding for Customer Assistance Programs (OnTrack) and the Low
6 Income Usage Reduction Program (WRAP). Finally, the Company believes it
7 has identified the appropriate level and source of funding for both programs.

8 Mr. Epstein expresses concern about the apparent drop in WRAP funding
9 from 2007 through 2009. The Company has proposed to increase the WRAP
10 budget from \$5.7 million to \$6.7 million and to ramp up the additional \$1 million in
11 WRAP spending over a period of three years (2005 through 2007). However, the
12 Company would begin collecting the full \$1 million from customers in 2005. As a
13 result of the ramp up of expenditures, PPL Electric would under spend in the first
14 three years (2005 through 2007) and overspend in the next three years (2008
15 through 2010). The WRAP budget evens out at the proposed level of \$6.7
16 million in 2011.

17 Witness Epstein notes that PPL Electric's administrative cost for WRAP is
18 out of balance and needs a downward adjustment. The Company attempts to
19 keep administrative costs for WRAP at 15 percent or lower. PPL Electric
20 disagrees with Mr. Epstein's assertion that the projected administrative costs for
21 WRAP from 2005 through 2007 average almost 20 percent. The Company has
22 estimated the administrative costs at 15 percent for each year (e.g.,
23 \$900,000/\$6.0 million, \$975,000/\$6.5 million and \$1,005,000/\$6.7 million).

1

2 Q. Does the Company have any concerns with the witnesses' recommendations
3 and comments regarding Operation HELP?

4 A. Yes, Witness Colton recommends that PPL Electric be required to submit to the
5 Commission, ninety days after the disposition of the rate case, a detailed work
6 plan through which the Company would increase donations to Operation HELP
7 by 20 percent. PPL Electric disagrees with this recommendation for several
8 reasons. First, as a threshold matter, Operation HELP is a voluntary program not
9 reflected in customers' rates. The scope and size of Operation HELP are
10 matters for PPL Electric to determine. Second, it is unreasonable to expect that
11 the Company could increase donations to the program by 20 percent. Operation
12 HELP is a long established program (begun in 1983) that, after 20 years of
13 continuous operation, is probably nearing the saturation point on the number of
14 monthly contributors. Third, it is important to remember the purpose of Operation
15 HELP. The Company started the program as a way to help customers who were
16 low income but not income eligible for LIHEAP. This supplemental program
17 could provide aid to working poor families or assist customers when LIHEAP
18 benefits were no longer available. It was never PPL Electric's purpose to grow
19 Operation HELP into a program that would address a broad range of needs.

20 Fourth, the program is supported totally by donations. PPL Electric is
21 proud of what the program has accomplished over the years (i.e., \$13.5 million in
22 donations and 52,000 customers assisted), and the Company attributes a lot of
23 the success to the strong support received from customers. Even though PPL

1 Electric enjoys a high level of customer satisfaction and loyalty, it is unrealistic to
2 expect a significant increase in the level of customer donations. Fifth, the
3 reasons why individuals contribute money for charitable purposes are varied and
4 complex. A variety of external (e.g., state of the economy) and internal (e.g.,
5 personal values) factors could affect contributions. Simply asking people more
6 often to give money may not produce the expected results.

7 Finally, PPL Electric is very concerned about the customers
8 (approximately 18,000) who have contributed faithfully over the years to
9 Operation HELP via their electric bills. Conducting an aggressive fund-raising
10 campaign immediately after an increase in rates could have a negative effect on
11 current or potentially new contributors. Customers could view such a campaign
12 as being too self-serving and needed only because the Company has increased
13 its rates.

14
15 Q. Does PPL Electric have other concerns regarding Operation HELP?

16 A. Yes, Witness Colton indicates that customer donations to Operation HELP have
17 fallen from 2001 through 2003 even though the number of residential customers
18 has increased during this same period of time. The Company is not convinced
19 there is any relationship between the number of Operation HELP contributors
20 and the number of residential customers. The reasons for contributing are
21 complex and may have nothing to do with an increase in the number of
22 customers. Furthermore, the increase in total residential customers was very
23 modest over this three-year period (2.5 percent), which would tend to mitigate

1 any impact on the number of new contributors.

2 Mr. Colton notes that PPL Electric has consistently fallen short by 15
3 percent of its goal to raise \$440,000 annually in donations from its customers,
4 employees and retirees. The Company disagrees with this conclusion. The
5 following table shows that PPL Electric has been achieving its fund-raising
6 objective for customers, employees and retirees over the past three years.

7

Year	Funds Raised	% of Goal
2001	\$450,348	102.4%
2002	\$436,307	99.2%
2003	\$430,530	97.8%
Total	\$1,317,185	99.8%

8

9 Witness Colton also recommends an increase in the level of support from
10 shareholders. PPL Corporation, through its Public & Charitable Contributions
11 budget, has provided \$440,000 annually in funding to Operation HELP for the
12 past several years. This amount matches the fund-raising objectives established
13 by PPL Electric for annual donations from its customers, employees and retirees.
14 PPL Corporation does periodically evaluate the level of shareholder funding for
15 Operation HELP and has increased the amount (e.g., from \$120,000 in 1986 to
16 \$300,000 in 1990 to \$325,000 in 1994).

17 Witness Colton, in his recommendation to have PPL Electric increases
18 Operation HELP donations by 20 percent, suggested that new fund-raising
19 strategies for hardship funds include seeking regular contributions from
20 customers rather than one-time donations and allowing customers to give to the
21 hardship fund on-line. Since the start of Operation HELP in 1983, PPL Electric

1 encouraged customers to give to the program via their electric bills.

2 Approximately 18,000 customers give monthly to Operation HELP in this manner.

3 The Company requests customers to give \$1, \$2, or \$5 monthly, but the flexibility

4 of its information system allows customers to give any amount for any specified

5 period of time within a year (e.g., \$10 monthly from November through March).

6 Customers who pay on-line have the ability to contribute to Operation HELP.

7 Witnesses Brady and Howat recommend that PPL Electric should allocate

8 Operation HELP funds on a more equitable basis. The Company allocates

9 funding based on several factors: low-income population, expenditure trends of

10 the administering agencies and overall customer needs in the various operating

11 areas. The Company does not look at individual agencies or counties when

12 allocating Operation HELP funds. Rather, PPL Electric considers the aggregate

13 funding needs of an area (e.g., the Company's northeast area includes Hazleton,

14 Scranton, Wilkes-Barre and Honesdale). The Company does look at the needs

15 of each area annually and, when appropriate, will adjust funding levels. PPL

16 Electric attempts to offer funding that matches areas' needs while ensuring that

17 all Operation HELP agencies receive a meaningful amount of funding.

18 Witness Epstein recommends that PPL Electric should match ratepayer

19 contributions to Operation HELP. The Company would like to note that

20 donations to the program are truly donations because there are no rate charges

21 for Operation HELP. For several years PPL Corporation has provided \$440,000

22 in funding from shareholders for Operation HELP. The amount of annual

23 customer donations to the program has averaged approximately \$379,000 over

1 the past four years. In other words, the Company's annual donation has
2 exceeded that of customers.

3
4 Q. Do you have any final issues you would like to address regarding the witnesses'
5 testimony on universal service programs?

6 A. Yes, I would like to respond to concerns raised by Witnesses Brady and Howat.

7 Mr. Brady asserts that PPL Electric is not qualified to design and implement
8 universal service programs. As such, that responsibility should lie solely with
9 community-based organizations like the Commission on Economic Opportunity.

10 Furthermore, because PPL Electric is not accountable to the communities it

11 serves and is conflicted by a duty to shareholders, the CBOs are singularly suited

12 to speak on behalf of communities' needs. Witness Brady also implies that the

13 Company implements these programs only for public relations purposes.

14 PUC regulations at 52 Pa. Code § 54.74 require utilities to submit

15 Universal Service and Energy Conservation Plan every three years for

16 Commission review and approval. Witness Howat recommends that PPL Electric

17 be required to have community-based organizations meet with the Company,

18 make written proposals and provide formal comments regarding the three-year

19 plan. Mr. Howat also suggests that the Commission require PPL Electric to

20 attach the CBOs' comments to its submission of the plan.

21
22 Q. What are your concerns with the recommendations of Witnesses Brady and
23 Howat?

1 A. PPL Electric takes exception to the assertion that it lacks the expertise to develop
2 and implement customer programs. The Company has decades of experience in
3 these areas and has a very successful track record of implementation. The
4 ultimate responsibility and accountability for expenditure of customer funds lies
5 solely and correctly with PPL Electric and not with non-profit organizations.
6 Nevertheless, the Company has worked extensively with CBOs for many years to
7 implement and improve low-income programs and will continue to do so. The
8 Company also objects to the conclusion that CBOs are best suited to speak on
9 behalf of customer needs because PPL Electric is conflicted by responsibilities to
10 shareholders. Whereas the CBOs involved in universal service programs have a
11 narrow focus (e.g., low-income households), PPL Electric has a broad focus that
12 encompasses a variety of areas (e.g., economic development, community
13 betterment, low-income customers, reliability of service, safety and
14 environmental). As part of their regular jobs or as volunteers in a myriad of
15 activities, PPL Electric employees are involved in their local communities.

16 The fact that PPL Corporation dutifully addresses the needs of
17 shareholders and achieves certain financial milestones allows the Company to
18 support activities in local communities. Finally, PPL Electric has implemented its
19 universal service programs for the primary purpose of addressing the needs of
20 customers. Any public relations' benefits that the Company may have received
21 as a result of these programs are more by accident than by design. PPL Electric
22 has not conducted any advertising campaigns to tout its involvement in low-
23 income programs.

1 The Company believes that the Commission has sufficient oversight
2 regarding the development of the three-year plans for universal service
3 programs. Mr. Howat's suggestion would require the Commission to change its
4 regulations, which PPL Electric believes is unnecessary and unwarranted. The
5 Company suggests that making changes to these regulations, which affect all
6 jurisdictional electric and gas utilities, during a rate case proceeding for a specific
7 utility is an inappropriate venue.
8

9 IV. PPL Electric's Responses to Recommendations
10 Re: Sustainable Energy Fund

11 Q. What are the positions and perspectives of the various witnesses regarding the
12 Sustainable Energy Fund ("SEF" or "Fund")?

13 A. There is a clear polarization of positions among the various witnesses regarding
14 the continuation of funding for the SEF. Witnesses Prisco, Baron and Gruber all
15 recommend the cessation of funding, while Witnesses Hanger, Schwarz, Link,
16 Howat and Brady express support for continued funding with some caveats. For
17 example, Witness Hanger suggests a doubling of funding for the SEF, Witness
18 Schwarz proposes that the Pennsylvania Energy Development Authority
19 ("PEDA") manage the SEF and Witnesses Howat and Brady recommend that the
20 SEF allocate 36 percent of its annual funding for a residential photovoltaic ("PV")
21 program. Witness Link proposes that the Commission set standards for the
22 Fund, including compensation for Board members.
23

24 Q. What is PPL Electric's recommendation regarding the Sustainable Energy Fund?

1 A. PPL Electric is proposing a compromise position that would allow funding for the
2 SEF to continue using the existing funding mechanism (i.e., .01 cents per kWh
3 for all power sold to all customers) for a period of five years ending December
4 31, 2009.

5
6 Q. What are the Company's concerns regarding various recommendations to stop
7 all customer funding of the SEF?

8 A. Witness Prisco suggests eliminating funding for the SEF because the program
9 does not support life cycle cost effective conservation measures that are included
10 in Executive Order 13123, Section 203. PPL Electric disagrees with this
11 conclusion because the types of projects funded by the SEF include a variety of
12 activities (e.g., wind development, green building and emerging electric
13 technologies). PPL Electric agrees with Witness Prisco's assertion that the SEF
14 has adequate funding to sustain operations for several more years. However,
15 that conclusion misses the point. What is important is that the SEF evolve into a
16 viable and fully sustainable entity. The Fund focuses on issuing loans, making
17 equity/royalty investments and providing grants on a limited basis. The SEF has
18 made investments that are returning money on a regular basis, but it usually
19 takes several years to realize the biggest returns. Fledging companies normally
20 need time to establish themselves and the SEF is no different.

21 Witnesses Baron and Hanger assert that PPL Corporation's shareholders
22 and not distribution customers have actually paid for the SEF. PPL Electric
23 disagrees with this assertion. The language of the Company's 1998 Settlement

1 Agreement stated that the SEF would be funded from the distribution charges in
2 each rate schedule at the rate of .01 cents per kWh on all power delivered to all
3 customers. Clearly, the Commission intended that all customers fund the SEF
4 through their distribution charges. The Company has tariff language approved by
5 the Commission regarding the use of a portion of distribution charges for all
6 customers to pay for the SEF. The funding mechanism for the SEF underwent
7 comprehensive discussion, review and approval by all parties during PPL
8 Electric's 1998 Settlement Agreement.

9 Witness Baron argues that the SEF is not a cost of providing distribution
10 services; the SEF is a research and development fund that does not enhance the
11 distribution system; and the SEF supports supply-side projects that violate cost
12 allocation and rate making principles for distribution charges. PPL Electric
13 disagrees with this conclusion. The SEF has provided funds to a variety projects
14 that would provide benefits to all facets of electric service. For example, the SEF
15 has provided funding for projects over a variety of areas ranging from the Bear
16 Creek wind energy project near Wilkes-Barre to the certified green building
17 project for the Londonderry School in Harrisburg to PowerWeb Technologies,
18 Inc. for software development of internet load management applications. Since
19 all customers pay distribution charges, the Company believes it is appropriate to
20 assign SEF costs to all classes of customers.

21 Mr. Baron states that the purpose of the Competition Act ("Act") was to
22 deregulate energy supply and to allow customers to shop for alternative energy
23 supply. Witness Baron asserts that the Commission is reintroducing regulatory

1 mandates on generation service by forcing distribution customers to subsidize
2 the SEF. PPL Electric believes that Mr. Baron's characterization of the purpose
3 of the Act is too narrow. The Act addressed other important issues regarding the
4 quality of customer service, availability of programs and services and the
5 continuation of programs for low-income customers. The Company disagrees
6 with Mr. Baron's assertion regarding the reintroduction of regulatory mandates on
7 generation service by the Commission. As noted earlier by PPL Electric, all
8 customers pay for the SEF through their distribution rates, which the Commission
9 approved as a result of the 1998 Settlement Agreement.

10 Witness Gruber asserts that continuing the funding of the SEF is
11 tantamount to a hidden tax because the state budget contains funding proposals
12 for environmental issues. From the Company's perspective, there is nothing
13 hidden about the recommendation to continue funding for the SEF. PPL Electric
14 believes that the SEF is serving an important niche market (i.e., renewable
15 energy technologies and energy conservation and efficiency) with a focus that
16 does not exist with other governmental or private entities. If the SEF were able
17 to leverage state funding to expand its projects and reach, then benefits would
18 accrue to PPL Electric's customers and communities.

19
20 Q. Has PPL Electric identified any concerns or issues regarding the
21 recommendations of those witnesses who support the continuation of funding for
22 the SEF?

23 A. Yes, PPL Electric does not support Witness Hanger's recommendation to double

1 the funding for the SEF from .01 cents per kWh to .02 cents per kWh. The
2 Company agrees with Mr. Hanger that there are opportunities for more work in
3 the area of renewable energy technologies and energy conservation and
4 efficiency but disagrees on the source and level of the funding. Witness Hanger
5 reluctantly admits that meaningful taxpayer funding for renewable energy
6 programs is not forthcoming. As a result, the primary funding sources for these
7 activities must perforce come from utilities and ratepayers. The fact that most
8 state legislatures do not consider renewable energy as a critical public policy
9 issue (i.e., using taxpayers dollars to support programs) is a telling sign. Using
10 electric utilities as “government by other means” may not result in the best,
11 overall public policy.

12 Nevertheless, PPL Electric recognizes the difficulties presented by the
13 *competing needs and priorities for state funding and the importance of*
14 *addressing environmental issues in a sustained manner.* As such, the Company
15 has proposed to continue funding the SEF for another five years. PPL Electric
16 does not believe it is fair or equitable to have ratepayers, particularly low-income
17 households, carry indefinitely the bulk of the funding load for expanding
18 renewable energy activities. The Company’s proposal would provide meaningful
19 funding, allow the SEF to further establish its sustainability and minimize the cost
20 impact on customers.

21 Witness Hanger states that he is unaware of any requirement (e.g., PUC
22 Order) “... that imposes any assumption that PPL/customer funding for SEF
23 “should” expire...” In the Joint Petition for Full Settlement of PP&L Inc.’s

1 Restructuring Plan and Related Court Proceedings, at Docket No. R-009973954,
2 dated August 12, 1998, the Commission approved funding for the SEF that
3 began on January 1, 1999 and ended on December 31, 2004, or until the
4 Commission established new distribution rates, whichever is longer. PPL Electric
5 concludes from this provision of its Settlement Agreement that the Commission
6 did establish a firm expiration date. As part of its proposal for new distribution
7 rates, the Company is recommending the continuation of funding for the SEF.

8 Witness Schwarz stated that PPL Electric objected to responding to
9 interrogatories submitted by the Office of Small Business Advocate ("OSBA")
10 regarding SEF activities. The OSBA then submitted the interrogatories to the
11 SEF and is awaiting a response from the Fund. The Company objected to the
12 OSBA's interrogatories because they addressed SEF-specific issues (e.g.,
13 detailed resumes of Board members and Board members' qualifications for
14 investing in renewable energy technologies) best addressed by the Fund's
15 management. The SEF responded to the OSBA's interrogatories on July 2,
16 2004.

17 Mr. Schwarz's key recommendation is to turn over the management of the
18 SEF to the Pennsylvania Energy Development Authority ("PEDA"). He bases his
19 recommendation on several factors: PEDA has a mandate similar to the SEF;
20 PEDA is charged with financial renewable energy projects; PEDA can provide
21 better coordination of projects among the various SEFs; and PEDA can ensure
22 greater accountability. PPL Electric has several concerns regarding this
23 proposal.

1 First, Mr. Schwarz admits that PEDDA had been moribund and just recently
2 the Governor issued an executive order transferring its responsibilities to the
3 Department of Environmental Protection. In addition, PEDDA has not yet
4 developed its procedures for selecting and funding projects. Given these
5 developments, it seems premature to consider an expanded role for PEDDA
6 regarding involvement with the SEF. Second, PPL Electric believes that the
7 Commission has sufficient oversight responsibilities to ensure that the SEF meet
8 the requirements of the Settlement Agreement. For example, the Commission
9 approved the SEF's by-laws, approves new Board member and requires an
10 annual audit and semi-annual reports. The SEF provides these reports to the
11 Commission and parties from the 1998 Settlement Agreement. The Commission
12 also has a Pennsylvania Sustainable Energy Board (PASEB) that is charged
13 with:

- 14 • Offering guidance and technical assistance to the regional SEFs.
- 15 • Providing oversight in developing a best practices business model.
- 16 • Serving as a forum where the SEFs, Commonwealth agencies, public
17 officials and others can learn more about sustainable energy technologies.

18 Third, the Company has concerns about a state agency directing and
19 administering the expenditure of ratepayer funding. The SEF is not a tax-based
20 program that the General Assembly debated, approved and allocated funds
21 toward. PPL Electric would not support the expenditure of a majority of customer
22 funds in areas outside of its service territory. The Company's SEF is an
23 entrepreneurial entity that has a solid track record of accomplishment and has

1 worked hard to establish its sustainability. The SEF must have accountability
2 and oversight, which PPL Electric believes the Commission has provided, but the
3 Fund also needs the flexibility to identify projects and to move quickly and
4 prudently when needed. Adding another layer of bureaucracy and control does
5 not seem desirable.

6 PPL Electric certainly agrees that the Commission, PASEB, PEDDA and the
7 various Sustainable Energy Funds should work collaboratively to promote a
8 sustainable energy future for Pennsylvania. The Company also agrees that there
9 are opportunities to improve the coordination of the Funds and to share best
10 practices. However, the Company is not convinced that PEDDA should assume
11 the coordination mantle for Pennsylvania's SEFs.

12 Witness Schwarz expressed concern that the PUC-required annual audit
13 and reports did not provide information on the selection criteria for SEF projects.
14 Mr. Schwarz noted that the SEF resisted the reasonable requirement to explain
15 why the Fund rejects proposals. The SEF, of course, has a detailed and
16 standardized process for evaluating funding proposals. The SEF staff reviews all
17 funding proposals received to determine if the project warrants further
18 investigation. If the project shows promise, the staff conducts an evaluation that
19 includes, but is not limited to, costs, leveraging opportunities, associated risks
20 and the fit with the SEF's mission. After this assessment, the SEF staff reviews
21 the project proposal with a Board Committee charged with evaluating funding
22 proposals. If approved by this Committee, the full Board reviews the project
23 proposal and votes on whether to provide funding. The SEF rejects projects that

1 do not meet the evaluation criteria.

2

3 Q. Do you have any other concerns about the witnesses' recommendations for the
4 SEF?

5 A. Yes, witnesses Brady and Howat recommend that the Commission should
6 mandate 36 percent of the SEF's annual funding toward a photovoltaic ("PV")
7 grant program for all residential customers. Based on the SEF's funding from
8 2002, that percentage translates into approximately \$1.2 million. Witness Howat
9 proposes that the SEF allocate 17.6 percent to low-income customers and 82.4
10 percent to all other residential customers. Approximately 17.6 percent of
11 residential customers have annual household incomes at or below 150 percent of
12 the federal poverty level. Mr. Howat suggests a 100 percent grant program for
13 low-income customers and a one-to-one matching grant for other residential
14 customers. The four community-based organizations that participated in PPL
15 Electric's renewable energy pilot for low-income customers would handle all
16 facets of this proposed program (e.g., review PV grant applications, review
17 systems and inspect installations).

18 PPL Electric agrees that the SEF should be more involved in identifying
19 and implementing renewable energy projects for residential customers. This is
20 an area where the SEF could expand its activities. However, the Company does
21 not agree with allocating a set percentage of funding toward any class of
22 customer or any type of specific activity. First, there is nothing in PPL Electric's
23 Settlement Agreement regarding the allocation of funding to certain classes of

1 customers. Second, the SEF should have the flexibility to use its funding for
2 projects that provide the best value for the dollars invested. Designating funding
3 *for a specific technology (e.g., photovoltaic applications)* may prevent the SEF
4 from realizing greater benefits for customers in other areas of renewable energy
5 technologies. Finally, the Company is not convinced that providing grants to
6 residential customers for photovoltaic installations is the appropriate use of
7 funding.

8 For example, the payback period for residential photovoltaic applications
9 is, at best, approximately 30 years. Preliminary estimates for PPL Electric's
10 photovoltaic pilot participants are not encouraging. The average installation cost
11 of each PV unit for the Company's pilot was over \$10,000. The Company
12 expects these systems to reduce a customer's annual electric bill by \$136 (1,000
13 watts x 4.3 solar hours per day x 8.5 cents per kWh x 31 days x 12 months).
14 Under the Company's current rates, this equates to an average payback period
15 exceeding 70 years. Even with increased rates the payback period would still be
16 very lengthy.

17 Other challenges include finding suitable homes for PV installations (e.g.,
18 roof orientation and no shade trees), obtaining reliable equipment, maintaining
19 the systems and securing permission from landlords for installations. In PPL
20 Electric's pilot there was a major problem with the failure of inverters, which
21 change direct current into alternating current. The manufacturer eventually went
22 out of business. In the Company's regular weatherization program (i.e., WRAP),
23 approximately 30 percent of landlords refuse to give their permission to install

1 materials. It might be different if PV was a relatively new and developing
2 technology that warranted further testing; however, PV technology has been
3 around for years and has not proven to be cost effective for most residential
4 applications. With a proposed budget of \$1 million, the community-based
5 organizations ("CBOs") would have to install around 100 units annually. Given
6 PPL Electric's experience with its renewable energy pilot, in which the CBOs
7 struggled to identify and install 44 units, it would be difficult for the agencies to
8 complete 100 units annually.

9 Witness Howat recommends the expeditious use of SEF funding in the
10 community and asserts that the Fund is holding dollars for its own financial gain.
11 Mr. Howat further suggests that the SEF's Board of Directors ("Board") include a
12 representative from a CBO that serves the low-income population. With respect
13 to the issue of expending funds, the SEF early on was determined to operate in a
14 sustainable manner. The Fund decided not to allocate all of its funding as
15 grants; rather, the SEF focused on issuing loans and making equity/royalty
16 investments. The Board also reserved funds in investment accounts so that
17 there would be funds available beyond December 31, 2004. The Fund hired third
18 parties to manage the funds. As a supporting organization for a non-profit 501-
19 C(3) entity, it is clearly prudent and proper for the SEF to be a careful steward of
20 its funding. Approving loans, taking equity positions and issuing grants is an
21 ongoing process for the SEF that involves a variety of steps. Among the various
22 Funds in Pennsylvania, the SEF for PPL Electric has the best track record
23 regarding the implementation of projects and the Fund continues to make

1 progress. In 2004, the SEF has estimated expenditures of approximately \$3.3
2 million (i.e., 90 percent in loans/equity investments and 10 percent grants).

3 Regarding the issue of having a low-income advocate on the SEF's Board,
4 one of the original Board members, Mr. Alan Jennings, ably represented the
5 interests of low-income organizations. Mr. Jennings is the Executive Director of
6 the Community Action Committee of the Lehigh Valley, which is an organization
7 very similar in purpose and focus to the Commission on Economic Opportunity.

8 PPL Electric agrees with Witness Link's recommendation for the
9 Commission to set standards for the SEF. The Company believes that the
10 Commission's Pennsylvania Sustainable Energy Board ("PASEB") is fulfilling this
11 function by developing "best practices" in a variety of areas (e.g., project
12 evaluation, reporting and compensation for Board members) for all of the Funds
13 in the Commonwealth. The Commission has further oversight responsibilities
14 that include approving the Fund's by-laws, reviewing and approving Board
15 members and requiring an annual audit and semi-annual reports.

16
17 Q. Do you have any other comments or observations about the SEF?

18 A. Recognizing the strong opinions held by parties on both sides of the issue
19 regarding continued funding for the SEF, PPL Electric has attempted to offer a
20 compromise position that it believes is balanced and fair. The Sustainable
21 Energy Fund has a specific mission to achieve and no other state agency or
22 government exists with the same focus. State agencies have supported SEF
23 project initiatives, but in most of these projects the SEF has been the driving

1 force for implementation.

2 The continuation of the Fund supports broad public policy objectives
3 regarding the environment, establishes partnerships with government to address
4 environmental needs, promotes the development of renewable energy
5 technologies and helps to achieve a cleaner environment over the long run. The
6 Company believes that the SEF provides benefits to all classes of customers.
7 Survey research has shown that environmental issues are important to
8 customers and community leaders. From PPL Electric's perspective, the whole
9 arena of renewable energy technologies is still an evolving industry in
10 Pennsylvania. As such, the SEF needs additional time to further enhance its
11 capabilities, pursue new areas of environmental interest and expand its working
12 relationships and coordination with state government and other partners.

13
14 V. PPL Electric's Responses to Recommendations
15 Re: Community Betterment Initiative

16 Q. What has PPL Electric proposed regarding the Community Betterment Initiative
17 ("CBI")?

18 A. The CBI would assist community development organizations and human service
19 agencies in addressing local needs by providing grant funds that would leverage
20 matching funds from the state for targeted programs (e.g., economic
21 development and affordable housing). PPL Electric recommends \$2 million in
22 annual funding for the program -- \$1 million from customers and \$1 million from
23 PPL Corporation's shareholders.

1 Q. What are the witnesses' recommendations and concerns regarding the
2 Community Betterment Initiative?

3 A. Witness Prisco proposes to eliminate the \$1 million in ratepayer funding for the
4 CBI because the Company is already supporting conservation-oriented social
5 programs and customers should be able to choose what charitable programs
6 they would like to support. Witness Epstein endorses the CBI but recommends
7 that PPL Electric should match ratepayer funding for the program. Witness
8 Howat supports the CBI as proposed by the Company but recommends a formal
9 review process to oversee allocation of the funds and that the process should
10 include input from all relevant stakeholders. Witness Colton endorses the CBI
11 because the program would help address the need for universal service
12 programs and the costs of collections. Generating matching public and private
13 matching funding through the CBI would generate benefits for ratepayers as well.

14
15 Q. What are the Company's concerns regarding the recommendations of the
16 various witnesses?

17 A. PPL Electric disagrees with Witness Prisco's recommendation to eliminate
18 ratepayer funding for the Community Betterment Initiative. The Company clearly
19 has a vested interest in supporting economic and community development
20 efforts. More jobs, a sounder economy and strengthened communities provide
21 benefits to many. Survey research consistently shows that economic
22 development is one of the top priorities of local communities. Elected and
23 appointed officials and other community leaders view PPL Electric as a vital and

1 necessary partner. The ability of the CBI to more effectively access state funds
2 would be of great value to projects in local communities, especially with the
3 introduction of many new initiatives in the Economic Stimulus Package. A study
4 conducted by third party evaluators of PPL Electric's very successful Community
5 Partnership Program, which had similar features to the proposed CBI, showed a
6 return of over \$20 to local communities for every \$1 invested. The Company
7 also recognizes that it takes effective partnerships to address community needs
8 and concerns.

9 The CBI would promote and enhance a variety of partnerships among
10 community organizations, state agencies and PPL Electric, especially those that
11 emphasize themes of focusing development in appropriate places. From the
12 Company's perspective, a modest and reasonable amount of investment in
13 supporting the needs of local communities would provide solid returns to many
14 parties. The strengthened public-private partnerships would enhance the
15 communities' and the Commonwealth's reputation as places where sound
16 planning and cooperation produce results. New programs such as Business in
17 Our Sites and Keystone Innovation Zones that rely on such partnerships can be
18 more successful in PPL Electric's communities with the resources that CBI would
19 make available.

20 PPL Electric agrees with Witness Epstein's recommendation to match
21 ratepayer funding for the CBI. The Company has proposed to provide \$1 million
22 in shareholder funding for the program. However, the implementation of the CBI
23 by PPL Electric is contingent upon approval by the Commission of \$1 million in

1 annual funding from ratepayers.

2 The Company disagrees with Witness Howat's proposal to establish a
3 formal review process for allocation of funding for CBI projects that includes input
4 from all relevant stakeholders. First of all, PPL Electric sees a major conflict of
5 interest in having potential CBI grantees involved in the review and approval
6 process. The Company would conduct information meetings with community
7 organizations to explain the purpose of the CBI, its requirements, timeline, etc.
8 All interested parties would have an equal opportunity to apply for and receive
9 CBI grants.

10 Secondly, the Company would develop an internal review and approval
11 process for the program that would include the appropriate evaluation criteria.

12 PPL Electric would establish an internal team to ensure a thorough and objective
13 review of CBI proposals. An important decision-making criterion for this team
14 would be a proposal's compliance with an effective local development plan and
15 strategy. Stakeholders would have provided input through their participation in
16 the development and implementation of these local plans.

17 Thirdly, in addition to the conflict of interest concern, the Company
18 believes that it would be impractical and unwieldy to involve all relevant
19 stakeholders, which could number in the hundreds. It would be even more
20 difficult to select a representative sample of community organizations to provide
21 suggestions on the allocation of funds. Which organizations would be included
22 and why? Finally, PPL Electric has years of experience in evaluating and
23 awarding grants to organizations involved in economic and community

1 development activities. The review and approval process that the Company
2 established for the Community Partnership Program (1995 -1997) worked
3 effectively.

4

5 Q. *Does this conclude your rebuttal testimony?*

6 A. Yes, it does.