PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit PRM-1
Schedules Concerning Fair Rate of Return

Witness: Paul R. Moul
Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY

Schedules to Accompany

the Direct Testimony

of

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

Concerning

Fair Rate of Return

PENNSYLVANIA POWER & LIGHT COMPANY

Index of Schedules

Schedule 1
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Pennsylvania Power & Light Company
Capitalization and Financial Statistics
1989-1993, Inclusive

	1993	1992	1991	1990	1989	
			(Thousands of Dollars)			
Amount of Capital Employed						
Total Permanent Capital (incl.cap.leases)	$5,843,805	$5,794,368	$5,748,184	$5,610,174	$5,773,891	
Short-Term Debt	202,260	159,348	147,170	265,940	95,429	
Total-Capital Employed	$6,046,065	$5,953,716	$5,895,354	$5,876,114	$5,869,320	
Indicated Average Capital Cost Rates (1)						
Long Term Debt	7.8%	8.4%	8.2%	8.3%	8.5%	
Financial Ratios-Market Based						5 Year Average
Earnings/Price Ratio	7.2%	7.8%	8.5%	9.5%	10.5%	8.7%
Market/Average Book	181.2%	169.6%	158.1%	144.4%	138.7%	158.4%
Dividend Yield	5.8%	6.1%	6.6%	7.1%	7.4%	6.6%
Dividend Payout Ratio	79.8%	79.2%	77.2%	75.5%	70.6%	76.5%
Capital Structure Ratios						
Based on Total Permanent Captial:						
Long-Term Debt	49.8%	49.7%	49.6%	49.4%	51.8%	50.1%
Preferred Stock	8.7%	9.5%	10.4%	11.0%	11.1%	10.1%
Common Equity	41.5%	40.8%	40.0%	39.6%	37.1%	39.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	51.5%	51.0%	50.9%	51.7%	52.6%	51.5%
Preferred Stock	8.4%	9.2%	10.1%	10.5%	10.9%	9.8%
Common Equity	40.1%	39.8%	39.0%	37.8%	36.5%	38.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	13.1%	13.1%	13.4%	13.7%	14.6%	13.6%
Operating Ratios (2)	70.7%	70.8%	68.8%	67.1%	64.9%	68.5%
Coverages-Including All AFC (3)						
Before Income Taxes: All Interest Charges	3.4 x	3.3 x	3.2 x	3.0 x	2.9 x	3.2 x
After Income Taxes: All Interest Charges	2.4	2.4	2.4	2.3	2.2	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	2.0	2.0	2.0	1.9	2.0
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.4 x	3.2 x	3.2 x	3.0 x	2.9 x	3.1 x
After Income Taxes: All Interest Charges	2.4	2.3	2.3	2.2	2.2	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	2.0	2.0	1.9	1.9	2.0
Quality of Earnings						
AFC/Income Available for Common Equity	5.0%	4.9%	3.9%	4.1%	4.5%	4.5%
Effective Income Tax Rate	40.2	39.7	38.3	36.1	36.6	38.2
Internal Cash Generation/Gross Construction (4)	88.9	108.0	137.6	159.1	173.8	133.5
Gross Cash Flow/ Permanent Captial (5)	12.1	12.5	13.5	14.1	13.4	13.1
Gross Cash Flow/ Avg. Total Debt(6)	22.9	23.9	25.8	25.8	24.6	24.6
Gross Cash Flow Interest Coverage(7)	3.9 x	3.9 x	4.1 x	4.0 x	3.7 x	3.9 x
Common Dividend Coverage (8)	2.7	2.8	3.1	3.3	3.4	3.1

See Page 2 for Notes.

Pennsylvania Power & Light Company
Capitalization and Financial Statistics
1989-1993, Inclusive

Notes:

(1) Computed by relating actual long-term debt interest expense booked to average of beginning and ending long-term debt reported to be outstanding.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction), as reported in its entirety cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations and after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFC) as a percentage of Permanent Capital (long-term debt, current maturities and preferred, preference and common equity).

(6) Gross Cash Flow (as defined in Note 5) as a percentage of average total debt.

(7) Gross Cash Flow (as defined in Note 5) plus interest charges, divided by interest charges.

(8) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

	Bond Rating		Common Stock	S&P Common Stock	Market Sensitivity Statistics		Business
	Moody's	S&P	Traded	Ranking	Beta	R^2	Position
Pennsylvania Power & Light	A2	A-	NYSE	A-	0.74	0.28	Average

Source of Information: OneSource
Standard & Poor's Utility Compustat
Moody's Public Utilities Manual and Bond Survey
S&P Bond Guide and Creditweek
S&P Stock Guide
Merrill Lynch Security Risk Evaluation, July 1994

CORPORATE CONTINUED

PENNSYLVANIA POWER & LIGHT CO.

S&P Contact: Debra E. Bromberg (212) 208-1657

RATINGS ASSIGNED

Rule 415 shelf drawdowns:	
\$150 mil. 6.78% 1st mtg. bnds. due 3/1/04	A
\$100 mil. 7.38% 1st mtg. bnds. due 3/1/14	A
\$30 mil. 5.95% cum. pfd. stk.	A-
\$25 mil. 6.05% cum. pfd. stk.	A-
\$25 mil. 6.15% cum. pfd. stk.	A-

OUTLOOK: NEGATIVE

Pennsylvania Power & Light Co.'s (PPL) ratings reflect strong earnings, limited rate needs, and excellent plant operations, offset by heavy nuclear asset concentration, high debt use, and some Clean Air Act compliance exposure. The bulk of acid rain-related spending will occur in the mid-to-late 1990s and should result in a manageable 5.5% rate hike. If the utility is required to reduce nitrogen oxide emissions further to meet federal ambient ozone standards in the last half of the decade, an additional 4%-6% hike would be needed. Yet most outlays would be included in the rate base under a state law that allows for a cash return on CWIP. Debt leverage will remain aggressive, hovering around 52%, but new capacity will not be needed until the next century and internal cash flow should continue the bulk of outlays. Funds from operations (FFO) interest coverage is projected at about 3.5 times (x)-4.0x, and FFO to total debt in the 20%-22% range. Excellent operations at the two-unit Susquehanna nuclear station mitigates heavy asset concentration.

Notwithstanding the lack of an equity return on unit 2, PPL has achieved a return on equity of more than 13% and pretax interest coverage of over 3.0x. This is due to profitably marketing generation capacity and energy to other utilities, refinancing of high-cost debt, efficient operations, and cost control. PPL has not raised rates since 1985 and successful efforts in the wholesale power market should offset attrition-based rate needs until the mid-1990s.

OUTLOOK: NEGATIVE In view of the company's liberal debt use, limited sales growth prospects, and average business risk profile, financial indicators are projected to be weak for the ratings. The inability to maintain strong earnings and show capital structure improvement could result in modestly lower ratings.

POHANG IRON & STEEL CO. LTD.

S&P Contact: Noboru Wakayama, Tokyo (3) 3213-5301

RATING ASSIGNED

¥27.5 bil. 4.05% Japanese bnds. ser. 2 due March 24, 1999	A+

RATING AFFIRMED

Long-term debt	A+

OUTLOOK: STABLE

Pohang Iron & Steel Co. Ltd. (Posco), one of Korea's top companies and the country's only integrated steel producer, holds a dominant market position and enjoys substantial export sales. Posco's chief strengths are its very low-cost position and high operating efficiency; it also has good product capabilities and improving R&D and technical capabilities. These traits should enable the company to sustain its high profitability, retain its strong international competitive position, and weather potential industry or economic difficulties. Moreover, the Korean steel market is less risky than the steel markets of other rated steel companies due to rapid demand growth, limited domestic competition, and some government oversight and guidance.

However, Posco is exposed to the difficulties of the steel industry, including extreme capital intensity, cyclical fluctuations, and intense global competition. The company is further challenged by changes in the Korean economy, such as higher costs for labor and other local inputs.

Posco's rapid expansion has largely been debt-financed, resulting in moderately high debt levels and a substantial interest burden. However, the company's extremely aggressive depreciation rate understates equity and its ability to generate strong earnings protection. Posco is 35% owned, directly and indirectly, by the government. However, little governmental support is factored into the rating, as historically close ties to the government gradually are being reduced.

OUTLOOK: STABLE Posco has completed major expansion projects of its steel business. The government recently choose Posco to lead a consortium to develop a second mobile telephone network in Korea. While this will require sizable cash investment over a period of years, the costs will be shared among a number of major partners and should not prevent the company from gradually improving its capital structure.

lion in revenue in 1990. Much of this growth has been achieved through acquisitions (over C$445 million in the last three years). Given the industry trend towards consolidation and the company's continuing growth strategy, Loewen's acquisition activity is likely to remain sizable. Loewen's operating margins of around 29% reflect the company's success to date in integrating its newly acquired operations. However, investment activity continues to well exceed Loewen's ability to internally fund its growth. Several small equity issues and this issue have lowered debt leverage in recent years to the current 50% range. Still, funds from operations relative to acquisition and capital spending requirements was only 31% in 1993.

OUTLOOK: POSITIVE External financing of Loewen's active acquisition program is likely to remain high. However, internal cash generation should improve as operating efficiencies from newly acquired funeral homes continue to be realized. Provided that the company's future growth does not result in higher leverage levels, and operating margins continue to improve, the rating may be upgraded within the next few years.

PENNSYLVANIA POWER & LIGHT CO.
PENNSYLVANIA POWER & LIGHT ENERGY TRUST

S&P Contact: Debra Bromberg (212) 208-1657

DOWNGRADED

	TO	FROM
Pennsylvania Power & Light Co.		
Sr. secd. debt	A-	A
Pfd. stk.	BBB+	A-
Comm. pap.	A-2	A-1
Pennsylvania Power & Light Energy Trust		
Comm. pap.	A-2	A-1

Total debt: about $3 bil.

OUTLOOK: STABLE

Pennsylvania Power & Light Co.'s and Pennsylvania Power & Light Energy Trust's downgrades reflect prospects for insufficient financial improvement, despite the initiation of a new issue dividend reinvestment plan in 1994 and sharp reduction in the construction budget. Cash flow and capital structure strengthening over the intermediate term will be constrained by a high common dividend payout and some external financing requirements, in part to fund Clean Air Act (CAA) compliance spending. Also, despite strong weather-related sales growth earlier this year and cost containment, earnings will come under some pressure due to various modestly sized electric rate reductions, disallowances and write-offs, and declining prospective authorized returns on equity (ROE). The company's last authorized ROE, in 1985, was a high 15.5%.

Pennsylvania Power & Light will need rate relief beginning in 1995-1996, largely tied to CAA expenditures, additional Susquehanna nuclear plant depreciation, decommissioning, deferred operating costs, and incremental SFAS 106 expense. However, further success in marketing surplus generating capacity, or in achieving additional cost savings through an expected restructuring of operations, could mitigate rate requirements during the next several years.

OUTLOOK: STABLE The outlook is supported by prospects for modest longer-term financial improvement (particularly as CAA spending winds down), limited exposure to increasing competition (many larger customers have competitively-priced interruptible rates), and consistent nuclear operating performance.

PHOENIX HOME LIFE MUTUAL INSURANCE CO.
PHOENIX AMERICAN LIFE INSURANCE CO.

S&P Contacts: David A. Havens (212) 208-8326, Robert Partridge (212) 208-8551

OUTLOOK REVISED

	TO	FROM
Status	Pos.	Stable

RATINGS AFFIRMED

Claims-paying ability	AA-
Gtd. debt	AA-

OUTLOOK: POSITIVE

Phoenix Home Life Mutual Insurance Co.'s (Phoenix Home Life) and subsidiary Phoenix American Life Insurance Co.'s outlook revision affects only the company's guaranteed debt issues. During 1993 and 1994, Phoenix Home Life has made substantial strides in lowering its exposure to problem mortgages and real estate, improving the soundness of its capital base and strengthening earnings potential by cutting over $70 million of annualized expenses in the wake of the 1992 merger between Phoenix Mutual and Phoenix Home Life.

During 1993, the company disposed of more than $820 million in performing and nonperforming mortgages and real estate at minimal loss through active portfolio management. Consequently, real estate assets declined to 21% of total assets in 1993 from 30% in 1992. Capitalization was substantially bolstered as statutory capital increased to a strong $721 million in 1993 from $647 million in 1992. Net operating income played a major role as it mushroomed to $104 million in 1993 from $15 million in 1992, reflecting lower merger expenses and sound results from the core individual life and group lines. Also, Phoenix Home Life sold the former Home Life's group medical business, housed in their Home Life Financial Assurance Corp. subsidiary, creating a realized capital gain of $50 million.

OUTLOOK: POSITIVE The outlook reflects the ongoing progress the company has made in asset quality, earnings, expense control and capitalization. In the future, S&P believes the company will be challenged to expand the productivity of the individual sales force.

Barometer Group of Eight Electric Companies
Capitalization and Financial Statistics (1)
1989-1993, Inclusive

	1993	1992	1991 (Thousands of Dollars)	1990	1989	5 Year Average
Amount of Capital Employed						
Total Permanent Capital	$5,314,474	$5,182,525	$4,998,591	$4,699,037	$4,494,227	
Short-Term Debt	184,327	152,307	200,394	243,237	168,626	
Total Capital Employed	$5,498,800	$5,334,832	$5,198,985	$4,942,274	$4,662,853	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	5.9%	6.0%	6.1%	6.2%	6.4%	
Financial Ratios-Market Based						
Earnings/Price Ratio	7.2%	7.5%	8.4%	8.1%	10.2%	8.3%
Market/Average Book	162.6%	149.8%	135.8%	130.5%	136.1%	142.9%
Dividend Yield	6.3%	6.9%	7.6%	7.9%	7.6%	7.3%
Dividend Payout Ratio	89.6%	91.3%	91.3%	113.2%	74.9%	92.0%
Capital Structure Ratios						
Based on Total Permanent Captial:						
Long-Term Debt	48.3%	48.5%	49.4%	49.6%	48.2%	48.8%
Preferred Stock	7.6%	8.0%	7.7%	7.5%	7.3%	7.6%
Common Equity	44.2%	43.5%	42.9%	42.9%	44.5%	43.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	49.6%	50.0%	51.1%	51.9%	49.9%	50.5%
Preferred Stock	7.4%	7.8%	7.4%	7.2%	7.1%	7.4%
Common Equity	43.0%	42.2%	41.4%	41.0%	43.0%	42.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	11.5%	11.3%	11.4%	10.5%	13.8%	11.7%
Operating Ratios (3)	76.4%	78.2%	78.0%	78.5%	76.6%	77.5%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	3.1 x	3.0 x	2.9 x	2.6 x	3.1 x	2.9 x
After Income Taxes: All Interest Charges	2.4	2.3	2.3	2.2	2.5	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	2.0	2.0	1.9	2.2	2.1
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.0 x	2.9 x	2.7 x	2.4 x	2.9 x	2.8 x
After Income Taxes: All Interest Charges	2.3	2.2	2.1	1.9	2.3	2.2
Overall Coverage: All Interest + Pfd. Div.	2.0	1.9	1.9	1.7	2.0	1.9
Quality of Earnings						
AFC/Income Available for Common Equity	6.5%	7.9%	15.1%	30.9%	21.2%	16.3%
Effective Income Tax Rate	33.4	32.6	31.8	28.6	29.6	31.2
Internal Cash Generation/Gross Construction (5)	67.3	74.9	57.9	47.7	55.9	60.7
Gross Cash Flow/ Permanent Captial (6)	9.9	10.0	9.7	9.5	10.1	9.8
Gross Cash Flow/ Avg. Total Debt(7)	20.2	20.0	18.9	18.4	20.5	19.6
Gross Cash Flow Interest Coverage(8)	3.7 x	3.6 x	3.4 x	3.3 x	3.5 x	3.5 x
Common Dividend Coverage (9)	2.2	2.2	2.1	2.0	2.1	2.1

See Page 2 for Notes.

Barometer Group of Eight Companies
Capitalization and Financial Statistics
1989-1993, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Computed by relating actual long-term interest expense booked to average beginning and ending long-term debt reported to be outstanding.
(3) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.
(4) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations and after payment of all cash dividends.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFC) as a percentage of Permanent Capital (long-term debt, current maturities and preferred, preference and common equity).
(7) Gross Cash Flow (as defined in Note 6) as a percentage of average total debt.
(8) Gross Cash Flow (as defined in Note 6) plus interest charges, divided by interest charges.
(9) Common dividend coverage is the relationship of internally-generated funds from operations and after payment of preferred stock dividends to common dividends.

Basis of Selection:

The criteria used in the selection of this barometer group of Electric Companies were to include those companies that are included in Standard & Poor's Utility Compustat II, have SIC Code, 4911 (Electric Services) and 4931 (Electric and other services combined), common stock which is traded on the NYSE, operate in Pennsylvania or the six contiguous states to it, have not cut or omitted their dividends, have 1993 operating revenues above $750 million.

	Bond Rating		Common Stock	S&P Common Stock	Market Sensitivity Statistics		Business
	Moody's	S&P	Traded	Ranking	Beta	R^2	Position
Allegheny Power System(1)	Aa3	A+	NYSE	A-	0.62	0.18	High Average
American Electric Power Co. (2)	Baa1	BBB+	NYSE	B+	0.76	0.23	Somewhat Above Avg.
Atlantic Energy, Inc. (3)	A3	A-	NYSE	A-	0.66	0.16	Low Average
Baltimore Gas & Electric Co.	A1	A+	NYSE	A	0.74	0.27	Average
Delmarva Power & Light Co.	A2	A	NYSE	B+	0.57	0.08	Average
DPL, Inc. (4)	A1	AA-	NYSE	B+	0.56	0.07	High Average
Potomac Electric Power Co.	A1	A+	NYSE	A-	0.74	0.21	Somewhat Above Avg.
Public Service Enterprise Group (5)	A2	A-	NYSE	B+	0.75	0.29	Somewhat Below Avg.
	A2	A		A-	0.68	0.19	Average

Notes: (1) Bond ratings are a subsidiary composite.
(2) Bond ratings are a subsidiary composite.
(3) Bond ratings are those of Atlantic City Electric Co.
(4) Bond ratings are those of Dayton Power & Light Co.
(5) Bond ratings are those of Public Service Electric & Gas Co.

Source of Information: OneSource;
Standard & Poor's Utility Compustat II
Moody's Public Utility Manual and Bond Surveys
S&P Bond Guides, CreditWeek
S&P Stock Guides
Merrill Lynch Security Risk Evaluation, July 1994

Standard & Poor's Utility Index
Capitalization and Financial Statistics(1)
1989-1993, Inclusive

	1993	1992	1991	1990	1989	5 Year Average
Amount of Capital Employed						
Total Permanent Capital	$8,360,690	$8,466,694	$8,481,906	$8,271,060	$8,039,271	
Short-Term Debt	484,732	388,963	383,288	418,814	307,700	
Total Capital Employed	$8,845,422	$8,855,656	$8,865,194	$8,689,875	$8,346,971	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	4.9%	5.3%	5.6%	5.9%	6.5%	
Financial Ratios-Market Based						
Earnings/Price Ratio	4.6%	7.1%	5.9%	6.8%	7.6%	6.4%
Market/Average Book	216.2%	180.6%	170.7%	170.9%	163.5%	180.4%
Dividend Yield	4.9%	5.7%	5.8%	5.7%	5.6%	5.6%
Dividend Payout Ratio	99.6%	76.7%	95.3%	83.0%	74.2%	86.2%
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	48.3%	49.4%	50.1%	49.6%	48.7%	49.2%
Preferred Stock	4.4%	4.3%	4.3%	4.5%	4.8%	4.5%
Common Equity	47.3%	46.4%	45.6%	45.9%	46.5%	46.3%
	100.0%	100.1%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	51.1%	51.6%	52.3%	52.0%	50.6%	51.5%
Preferred Stock	4.2%	4.1%	4.1%	4.3%	4.6%	4.3%
Common Equity	44.7%	44.3%	43.6%	43.7%	44.8%	44.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	10.4%	12.8%	10.4%	11.5%	12.7%	11.6%
Operating Ratios (3)	86.9%	84.4%	85.2%	85.6%	84.7%	85.3%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	2.8 x	3.0 x	2.5 x	2.6 x	2.8 x	2.7 x
After Income Taxes: All Interest Charges	2.1	2.3	2.0	2.1	2.2	2.1
Overall Coverage: All Interest + Pfd. Div.	2.0	2.2	1.8	1.9	2.1	2.0
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	2.7 x	2.9 x	2.4 x	2.5 x	2.7 x	2.6 x
After Income Taxes: All Interest Charges	2.1	2.2	1.9	2.0	2.1	2.1
Overall Coverage: All Interest + Pfd. Div.	1.9	2.1	1.8	1.9	2.0	1.9
Quality of Earnings						
AFC/Income Available for Common Equity	5.7%	4.6%	7.0%	8.7%	8.9%	7.0%
Effective Income Tax Rate	35.9	34.3	34.8	34.2	32.4	34.3
Internal Cash Generation/Gross Construction (5)	104.8	95.6	90.9	88.2	87.8	93.1
Gross Cash Flow/ Permanent Capital (6)	16.6	15.0	14.5	14.0	14.3	14.9
Gross Cash Flow/ Avg. Total Debt(7)	30.6	27.7	26.8	26.6	27.9	27.9
Gross Cash Flow Interest Coverage(8)	4.8 x	4.3 x	4.0 x	3.9 x	4.0 x	4.2 x
Common Dividend Coverage (9)	3.3	3.2	3.2	3.1	3.2	3.2

See Page 2 for Notes.

Standard & Poor's Utility Index
Capitalization and Financial Statistics
1989-1993, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the aggregated result of the 47 companies in the group.
(2) Computed by relating actual long-term debt interest booked to average of beginning and ending long-term debt reported to be outstanding.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of capital additions to utility plant, provided by internally-generated funds from operations, excluding all AFC, and after payment of all cash dividends divided by gross contribution expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFC) as a percent of preference and common equity).
(7) Gross Cash Flow (as defined in Note 6) as a percentage of average total debt.
(8) Gross Cash Flow (as defined in Note 6) plus interest charges, divided by interest charges.
(9) Common dividend coverage is the relationship of internally-generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

Continued:

Standard & Poor's Utility Index
Capitalization and Financial Statistics
1989-1993, Inclusive

	June 30, 1994					
	Bond Rating		Common Stock	S&P Common Stock	Market Sensitivity Statistics	
	Moody's	S&P	Traded	Ranking	Adjusted Beta	R^2
Electric Utilities						
American Electric Power Co., Inc. (1)	Baa1	BBB+	NYSE	A-	0.76	0.23
Baltimore Gas & Electric Company	A1	A+	NYSE	A	0.74	0.27
Carolina Power & Light Company	A2	A	NYSE	A-	0.72	0.19
Central and South West Corp. (1)	Aa3	AA-	NYSE	A	0.60	0.09
Commonwealth Edison Company	Baa2	BBB	NYSE	B	0.60	0.06
Consolidated Edison Co., of NY, Inc.	Aa1	AA	NYSE	A	0.72	0.16
Detroit Edison Company	A3	BBB+	NYSE	A-	0.63	0.14
Dominion Resources, Inc. (1)	A1	A	NYSE	A	0.56	0.08
Duke Power Company	Aa2	AA-	NYSE	A-	0.64	0.14
Entergy Corp. (1)	Baa2	BBB	NYSE	B	0.80	0.26
FPL Group, Inc. (1)	A2	A	NYSE	A-	0.76	0.26
Houston Industries, Inc. (1)	A2	A	NYSE	B+	0.63	0.10
Niagara Mohawk Power Corp.	Baa2	BBB	NYSE	B	0.77	0.24
Northern States Power Company (2)	Aa2	AA	NYSE	A-	0.74	0.29
Ohio Edison Company (2)	Baa2	BBB-	NYSE	B	0.85	0.31
PSI Resources, Inc. (1)	Baa1	BBB+	NYSE	B	0.73	0.21
Pacific Gas & Electric Company	A1	A	NYSE	B+	0.72	0.20
Pacificorp (2)	A3	A-	NYSE	B+	0.61	0.12
PECO Energy Company (1)	Baa1	BBB+	NYSE	B	0.71	0.13
Public Service Enterprise Group (1)	A2	A	NYSE	B+	0.75	0.29
SCE Corp. (1)	Aa3	A+	NYSE	A	0.68	0.15
Southern Company (1)	A2	A	NYSE	A-	0.70	0.18
Texas Utilities Company (1)	Baa2	BBB	NYSE	A-	0.59	0.07
Union Electric (2)	A1	AA-	NYSE	A-	0.64	0.15
Average	A2	A		A-	0.69	0.17

Standard & Poor's Utility Index
Capitalization and Financial Statistics
1989-1993, Inclusive

	June 30, 1994					
	Bond Rating		Common Stock Traded	S&P Common Stock Ranking	Market Sensitivity Statistics	
	Moody's	S&P			Adjusted Beta	R^2
Natural Utilities						
Noram Energy Corp. (2)	Ba2	BB+	NYSE	B-	0.77	0.06
Coastal Corporation (1)	Baa2	BBB-	NYSE	B+	0.83	0.14
The Columbia Gas System, Inc.	Caa	D	NYSE	D	0.44	0.01
Consolidated Natural Gas Co.	A1	AA-	NYSE	A-	0.71	0.11
Eastern Enterprises (1)	A3	A	NYSE	B+	0.88	0.21
Enron Corporation (3)	Baa2	BBB	NYSE	B	0.61	0.05
ENSERCH Corporation	Baa2	BBB	NYSE	B	0.81	0.07
NICOR, Inc. (1)	Aa1	AA	NYSE	B	0.58	0.05
ONEOK, Inc.	Baa1	A-	NYSE	B	0.61	0.03
Pacific Enterprises (1)	A2	A+	NYSE	B-	0.79	0.09
Panhandle Eastern Corp. (1)	Baa3	BBB-	NYSE	B	1.20	0.22
Peoples Energy Corp. (1)	Aa3	AA-	NYSE	B+	0.66	0.09
Sonat, Inc. (1)	A3	A-	NYSE	B	0.83	0.13
Transco Energy, Inc. (1)	Ba2	BB	NYSE	B	0.76	0.03
Williams Company (1)	Baa3	BBB-	NYSE	B	1.01	0.26
Average	Baa1-	BBB-		B	0.77	0.10
Telecommunications Companies						
Ameritech Corp. (1)	Aaa	AAA	NYSE	A-	0.83	0.23
Bell Atlantic Corporation (1)	Aa2	AA+	NYSE	A-	0.82	0.20
BellSouth Corporation (1)	Aaa	AAA	NYSE	A-	0.77	0.21
GTE Corporation (1)	A1	AA-	NYSE	B+	0.90	0.37
NYNEX Corporation (1)	Aa3	A+	NYSE	A-	0.85	0.32
Pacific Telesis Group (1)	Aa3	AA-	NYSE	A-	0.86	0.13
Southwestern Bell Corp. (1)	A1	A+	NYSE	A-	0.88	0.26
US WEST, Inc. (1)	Aa3	AA-	NYSE	A-	0.77	0.24
Average	Aa2	AA		A-	0.84	0.25
Average for S&P Utilities	A2	A		B+	0.74	0.16
Indexes:						
S&P Public Utilities					0.76	0.39
S&P Industrials					1.01	0.98
S&P Composite					1.00	1.00

Notes: (1) Composite rating for subsidiaries of holding companies.
(2) Composite rating for parent company as well as subsidiaries.
(3) Parent Company rating.

Source of Information: Standard & Poor's Compustat Custom Business Unit
Moody's Public Utility Manual and Bond Survey
Standard & Poor's Stock and Bond Guide
Merrill Lynch Security Risk Evaluation, July 1994

Pennsivania Power & Light Company
Capitalization and Capital Structure Ratios
Based upon Investor-Provided Capital
Actual on September 30, 1994 and Estimated at September 30, 1995

	Actual on September 30, 1994			Estimated at September 30, 1995		
		Ratios			Ratios	
	Amount Outstanding ($000's)	Including S-T Debt	Excluding S-T Debt	Amount Outstanding ($000's)	Including S-T Debt	Excluding S-T Debt
Long-Term Debt (1)						
First Mortgage Bonds	2,455,000			2,559,500 (3)		
Other Long-Term Debt	313,789			313,750 (4)		
Loss on Reaquired Debt	(115,273)			(115,887)		
Total Long-Term Debt	2,653,516	45.42%	47.13%	2,757,363	45.67%	46.53%
Preferred Stock						
Preferred Stock	466,375			466,375		
Unrecovered Call Premium	(21,338)			(16,840)		
Total Preferred Stock	445,037	7.62%	7.90%	449,535	7.45%	7.59%
Common Equity:						
Common Stock	1,413,855			1,598,327 (5)		
Retained Earnings (2)	1,117,454			1,120,366 (6)		
Total Common Equity	2,531,309	43.33%	44.96%	2,718,693	45.03%	45.88%
Total Permanent Capital	5,629,862			5,925,591		
Short-Term Debt	212,000	3.63%		111,703	1.85%	
Total Capital Employed	5,841,862	100.00%	100.00%	6,037,294	100.00%	100.00%

Notes: (1) Includes current portion of long-term debt.
(2) Adjusted to exclude the unamortized call premiums on reaquired preferred and preference stock previously charged to retained earnings.
(3) Reflects the issuance of $200,000,000 of 7.70% Series First Mortgage Bonds on October 1, 1994 and redemption of $95,500,000 of the 9 1/4% Series during the period June through August 1995.
(4) Reflects the redemption of $55,000,000 of 9 3/8% Series in June or July 1995, planned issuance of $55,000,000 of the Series K bonds, and repayment of $39,000 other long-term debt.
(5) Reflects Company estimate of Capital Stock which includes the planned issuance of about $78,000,000 through the Dividend Reinvestment Plan, about $7,000,000 through the Employee Stock Ownership Plan and $100,000,000 received from common stock issued by PP&L Resources.
(6) Reflects Company estimate of Retained Earnings.

Source of Information Company provided data

Schedule 4

PENNSYLVANIA POWER & LIGHT COMPANY

Calculation of Composite Cost Rate of Long-Term Debt
At September 30, 1994
(Thousands of Dollars)

First Mortgage Bonds	Amount Outstanding	Percent to Total	Effective Interest Rate (a)	Average Weighted Cost Rate	
5-5/8 % Series Due 1996	$ 30,000	1.22 %	5.53 %	0.07 %	
6-3/4 % Series Due 1997	30,000	1.22	6.67	0.08	
5-1/2 % Series Due 1998	150,000	6.11	5.72	0.35	
7 % Series Due 1999	40,000	1.63	7.02	0.12	
8-1/8 % Series Due 1999	40,000	1.63	8.16	0.13	
6 % Series Due 2000	125,000	5.09	6.16	0.31	
7-1/4 % Series Due 2001	60,000	2.45	7.26	0.18	
7-5/8 % Series Due 2002	75,000	3.06	7.64	0.23	
7-3/4 % Series Due 2002	150,000	6.11	7.88	0.48	
7-1/2 % Series Due 2003	80,000	3.26	7.50	0.25	
6-7/8 % Series Due 2003	100,000	4.07	7.09	0.29	
6-7/8 % Series Due 2004	150,000	6.11	7.07	0.43	
6-1/2 % Series Due 2005	125,000	5.09	6.71	0.34	
6.55 % Series Due 2006	150,000	6.11	6.67	0.41	
7-3/8 % Series Due 2014	100,000	4.07	7.55	0.31	
9-1/4 % Series Due 2019	250,000	10.18	9.37	0.96	
9-3/8 % Series Due 2021	150,000	6.11	9.52	0.58	
8-1/2 % Series Due 2022	150,000	6.11	8.61	0.53	
7-7/8 % Series Due 2023	200,000	8.15	8.03	0.65	
6-3/4 % Series Due 2023	150,000	6.11	6.91	0.42	
7.30 % Series Due 2024	150,000	6.11	7.42	0.45	
Total	$ 2,455,000	100.00 %		7.57 %	
Pollution Control Series G					
9-3/8 % Series Due 2015	$ 55,000	17.53	9.76	1.71	
Pollution Control Series H					
6.40 % Series Due 2021	90,000	28.69	6.56	1.88	
Pollution Control Series I					
5.50 % Series Due 2027	53,250	16.97	5.67	0.97	
Pollution Control Series J					
6.40 % Series Due 2029	115,500	36.81	6.52	2.40	
Total	$ 313,750	100.00 %		6.96 %	
Total First Mortgage Bonds	$ 2,455,000	88.67	7.57	6.71	
Total Pollution Control Bonds	313,750	11.33	6.96	0.79	
Other Long Term Debt	39	0.00	8.00	0.00	
	2,768,789	100.00 %		7.50 %	
Long-Term Debt	2,768,789			7.50 %	$ 207,659 (b)
Loss on Reacquired Debt	(115,273)				7,101 (c)
Gain on Reacquired Debt					(82) (d)
Adjusted Long-Term Debt	$ 2,653,516			8.09 %(e)	$ 214,678

(a) Effective cost rate from Schedule B-6, page 2.
(b) 7.50% x $2,768,789
(c) Annualized amortization of loss on reacquired debt.
(d) Annualized amortization of gain on reacquired debt.
(e) $214,678 / $2,653,516

PENNSYLVANIA POWER & LIGHT COMPANY

Calculation of Composite Cost Rate of Long-Term Debt
At September 30, 1995
(Thousands of Dollars)

First Mortgage Bonds		Amount Outstanding	Percent to Total	Effective Interest Rate (a)	Average Weighted Cost Rate
5-5/8 % Series Due 1996		$ 30,000	1.17 %	5.53 %	0.06 %
6-3/4 % Series Due 1997		30,000	1.17	6.67	0.08
5-1/2 % Series Due 1998		150,000	5.86	5.72	0.34
7 % Series Due 1999		40,000	1.56	7.02	0.11
8-1/8 % Series Due 1999		40,000	1.56	8.16	0.13
6 % Series Due 2000		125,000	4.88	6.16	0.30
7-1/4 % Series Due 2001		60,000	2.35	7.26	0.17
7-5/8 % Series Due 2002		75,000	2.93	7.64	0.22
7-3/4 % Series Due 2002		150,000	5.86	7.88	0.46
7-1/2 % Series Due 2003		80,000	3.13	7.50	0.23
6-7/8 % Series Due 2003		100,000	3.91	7.09	0.28
6-7/8 % Series Due 2004		150,000	5.86	7.07	0.41
6-1/2 % Series Due 2005		125,000	4.88	6.71	0.33
6.55 % Series Due 2006		150,000	5.86	6.67	0.39
7.70 % Series Due 2009	(b)	200,000	7.82	7.85	0.61
7-3/8 % Series Due 2014		100,000	3.91	7.55	0.30
9-1/4 % Series Due 2019	(c)	154,500	6.04	9.37	0.57
9-3/8 % Series Due 2021		150,000	5.86	9.52	0.56
8-1/2 % Series Due 2022		150,000	5.86	8.61	0.50
7-7/8 % Series Due 2023		200,000	7.81	8.03	0.63
6-3/4 % Series Due 2023		150,000	5.86	6.91	0.40
7.30 % Series Due 2024		150,000	5.86	7.42	0.44
Total		$ 2,559,500	100.00 %		7.52 %
Pollution Control Series H 6.40 % Series Due 2021		$ 90,000	28.69	6.56	1.88
Pollution Control Series I 5.50 % Series Due 2027		53,250	16.97	5.67	0.96
Pollution Control Series J 6.40 % Series Due 2029		115,500	36.81	6.52	2.40
Pollution Control Series K 6.50 % Series Due 2025	(b)	55,000	17.53	6.58	1.16
Total		$ 313,750	100.00 %		6.40 %
Total First Mortgage Bonds		$ 2,559,500	89.08	7.52	6.70
Total Pollution Control Bonds		313,750	10.92	6.40	0.70
		2,873,250	100.00 %		7.40 %

Long-Term Debt	2,873,250	7.40 %	$ 212,621	(d)
Loss on Reacquired Debt	(115,887)		7,289	(e)
Gain of Reacquired Debt			(82)	(f)
Adjusted Long-Term Debt	$ 2,757,363	7.97 %(g)	$ 219,828	

(a) Effective cost rate from Schedule B-6, page 2.
(b) Bonds issued subsequent to September 30, 1994.
(c) $95,500 of bonds redeemed subsequent to September 30, 1994.
(d) 7.40% x $2,873,250
(e) Annualized amortization of loss on reacquired debt.
(f) Annualized amortization of gain on reacquired debt.
(g) $219,828 / $2,757,363

PENNSYLVANIA POWER & LIGHT COMPANY

Schedule of Long-Term Debt and Calculation
of Average Weighted Cost Rate at September 30, 1995

Description of Issue	Nominal Date of Issue	Date of Maturity	Amount Issued	Amount Outstanding	Amount Retired	Coupon Rate - %	Premium or (Discount) at Issuance	Issuance Expense	Net Proceeds	Annual Sinking Fund Requirement(1)	Average Term In Years	Net Proceeds Ratio	Effective Interest Rate
5-5/8 % Series Due 1996	6/1/66	6/1/96	$ 30,000,000	$ 30,000,000		5-5/8%	$ 470,970	$ 54,725	$ 30,416,245	$ 300,000	30	101.39	5.53 %
6-3/4 % Series Due 1997	11/1/67	11/1/97	30,000,000	30,000,000		6-3/4	378,300	54,843	30,323,457	300,000	30	101.08	6.67
5-1/2 % Series Due 1998	4/1/93	4/1/98	150,000,000	150,000,000		5-1/2	(1,264,500)	168,141	148,567,359		5	99.04	5.72
7 % Series Due 1999	1/1/69	1/1/99	40,000,000	40,000,000		7	(36,400)	65,884	39,897,716	400,000	30	99.74	7.02
8-1/8 % Series Due June 1, 1999	6/1/69	6/1/99	40,000,000	40,000,000		8-1/8	(80,000)	65,906	39,854,094	400,000	30	99.64	8.16
8 % Series Due 2000	6/1/93	6/1/00	125,000,000	125,000,000		8	(993,750)	137,817	123,868,433		7	99.09	8.16
7-1/4 % Series Due 2001	2/1/71	2/1/01	60,000,000	60,000,000		7-1/4	30,000	96,892	59,933,108	600,000	30	99.89	7.26
7-5/8 % Series Due 2002	2/1/72	2/1/02	75,000,000	75,000,000		7-5/8	(35,250)	110,041	74,854,709	750,000	30	99.81	7.64
7-3/4 % Series Due 2002	5/1/92	5/1/02	150,000,000	150,000,000		7-3/4	(1,182,000)	190,078	148,627,922		10	99.09	7.88
7-1/2 % Series Due 2003	1/1/73	1/1/03	80,000,000	80,000,000		7-1/2	79,200	115,987	79,963,213		30	99.95	7.50
6-7/8 % Series Due 2003	2/1/93	2/1/03	100,000,000	100,000,000		6-7/8	(1,185,000)	315,508	98,499,492		10	98.50	7.09
6-7/8 % Series Due 2004	3/1/94	3/1/04	150,000,000	150,000,000		6-7/8	(1,888,500)	180,604	147,930,896		10	98.62	7.07
6-1/2 % Series Due 2005	4/1/93	4/1/05	125,000,000	125,000,000		6-1/2	(2,045,000)	109,199	122,845,801		12	98.28	6.71
6.55 % Series Due 2006	3/1/94	3/1/06	150,000,000	150,000,000		6.55	(1,345,500)	183,693	148,470,807		12	98.98	6.67
7.70 % Series Due 2009 (2)	10/1/94	10/1/09	200,000,000	200,000,000		7.70	-	1,250,000	198,750,000		5 (3)	99.38	7.85
7-3/8 % Series Due 2014	3/1/94	3/1/14	100,000,000	100,000,000		7-3/8	(1,655,000)	122,873	98,222,127		20	98.22	7.55
9-1/4 % Series Due 2019 (4)	10/1/89	10/1/19	250,000,000	154,500,000	$95,500,000	9-1/4	(1,660,875)	197,679	152,641,446		30	98.80	9.37
9-3/8 % Series Due 2021	7/1/91	7/1/21	150,000,000	150,000,000		9-3/8	(2,001,000)	161,507	147,837,493		30	98.56	9.52
8-1/2 % Series Due 2022	5/1/92	5/1/22	150,000,000	150,000,000		8-1/2	(1,636,500)	189,347	148,174,153		30	98.78	8.61
7-7/8 % Series Due 2023	2/1/93	2/1/23	200,000,000	200,000,000		7-7/8	(3,230,000)	187,187	196,582,813		30	98.29	8.03
6-3/4 % Series Due 2023	10/1/93	10/1/23	150,000,000	150,000,000		6-3/4	(2,844,000)	174,957	146,981,043		30	97.99	6.91
7.30 % Series Due 2024	3/1/94	3/1/24	150,000,000	150,000,000		7.30	(2,037,000)	151,193	147,811,807		30	98.54	7.42
Pollution Control Series G													
9-3/8 % Series Due 2015 (5)	6/15/85	7/1/15	55,000,000	-	55,000,000	9-3/8	-	-	-		30	-	-
Pollution Control Series H													
6.40 % Series Due 2021	11/1/92	11/1/21	90,000,000	90,000,000		6.40	(787,500)	1,047,512	88,164,988		29	97.96	6.56
Pollution Control Series I													
5.50 % Series Due 2027	2/15/94	2/15/27	53,250,000	53,250,000		5.50	(998,438)	310,584	51,940,978		33	97.54	5.67
Pollution Control Series J													
6.40 % Series Due 2029	9/1/94	9/1/29	115,500,000	115,500,000		6.40	(990,990)	915,000 (6)	113,594,010		35	98.35	6.52
Pollution Control Series K													
6.50 % Series Due 2025 (2)	6/1/95	6/1/25	55,000,000	55,000,000		6.50	-	550,000	54,450,000		30	99.00	6.58

(1) The sinking fund requirements may be met with property additions or bonds.
(2) Bonds were issued subsequent to September 30, 1994, all information provided is budgeted information.
(3) The bondholders have the right to require the Company to redeem the bonds on October 1, 1999 at 100% of the principal amount.
(4) $95,500,000 redeemed subsequent to September 30, 1994
(5) Pollution Control series G redeemed subsequent to September 30, 1994
(6) Estimate

NOTE: No bonds under any series outstanding have been reacquired by the Company.

PENNSYLVANIA POWER & LIGHT COMPANY

Composite Cost Rate of Preferred Stock
At September 30, 1994
(Thousands of Dollars)

		Amount *Outstanding*	Percent *to Total*	Effective *Cost Rate (1)*	Weighted *Cost Rate*	Annual *Cost*
4-1/2 % Preferred		$ 53,019	11.37 %	5.03 %	0.57 %	$ 2,667
Series Preferred						
	3.35%	4,178	0.89	3.37	0.03	141
	4.60%	6,300	1.35	4.79	0.07	302
	4.40%	22,878	4.91	4.46	0.22	1,020
	6.33%	100,000	21.44	6.44	1.38	6,440
	6.125%	115,000	24.66	6.23	1.54	7,165
	6.75%	85,000	18.23	6.82	1.24	5,797
	5.95%	30,000	6.43	6.11	0.39	1,833
	6.05%	25,000	5.36	6.19	0.33	1,547
	6.15%	25,000	5.36	6.28	0.34	1,570
Total Preferred Stock		466,375	100.00 %		6.11 %	28,482
Unamortized Premiums and Unrecovered Original Issue Costs on Redeemed Stock (2)		(21,338)				4,498
		$ 445,037			7.41 % (3)	$ 32,980

(1) Effective cost rate from Schedule B-7, Page 2.
(2) See Schedule B-7, Page 3 for determination of this amount.
(3) $32,980 / $445,037

PENNSYLVANIA POWER & LIGHT COMPANY

Composite Cost Rate of Preferred Stock
At September 30, 1995
(Thousands of Dollars)

		Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate	Annual Cost
4-1/2 % Preferred		$ 53,019	11.37 %	5.03 %	0.57 %	$ 2,667
Series Preferred						
	3.35%	4,178	0.89	3.37	0.03	141
	4.60%	6,300	1.35	4.79	0.07	302
	4.40%	22,878	4.91	4.46	0.22	1,020
	6.33%	100,000	21.44	6.44	1.38	6,440
	6.125%	115,000	24.66	6.23	1.54	7,165
	6.75%	85,000	18.23	6.82	1.24	5,797
	5.95%	30,000	6.43	6.11	0.39	1,833
	6.05%	25,000	5.36	6.19	0.33	1,547
	6.15%	25,000	5.36	6.28	0.34	1,570
Total Preferred Stock		466,375	100.00 %		6.11 %	28,482
Unamortized Premiums and Unrecovered Original Issue Costs on Redeemed Stock (2)		(16,840)				4,359
		$ 449,535			7.31 % (3)	$ 32,841

(1) Effective cost rate from Schedule B-7, Page 2.
(2) See Schedule B-7, Page 3 for determination of this amount.
(3) $32,841 / $449,535

PENNSYLVANIA POWER & LIGHT COMPANY

Computation of Preferred Stock Effective Cost Rate by Series
At September 30, 1995

Description of Issue	Date of Issue	Date of Maturity(1)	Amount Issued	Amount Outstanding	Amount Retired	Gain on Reacquisition	Issuance Expenses Net of Premium	Net Proceeds(2)	Sinking Fund Requirements: Annual Requirements (Shares)	Sinking Fund Requirements: Redemption Period	Nominal Dividend Rate	Average Term in Years(1)	Net Proceeds Ratio	Effective Cost Rate (3)
Cumulative Preferred Stock														
3.35 % Series	5/2/46	*	$ 4,178,300	$ 4,178,300			$ 21,029	$ 4,157,271	-	-	3.35 %	*	99.50 %	3.37 %
4.60 % Series	10/21/46	*	8,300,000	8,300,000			248,899	8,051,101	-	-	4.60	*	96.05	4.79
4.40 % Series	8/5/52	*	22,877,300	22,877,300			316,821	22,560,479	-	-	4.40	*	98.62	4.46
4-1/2 % Series	12/10/45	*	53,018,900	53,018,900			154,373 (4)	47,435,627 (5)	-	-	4.50	*	89.47	5.03
	12/22/54	*												
6.33 % Series	6/10/93	7/1/08	100,000,000	100,000,000			1,056,645	98,943,355	50,000	2003-2007	6.33	14.25	98.94	6.44
									750,000	2008				
6.125 % Series	8/17/93	10/1/08	115,000,000	115,000,000			1,114,078	113,885,922	57,500	2003-2007	6.125	14.25	99.03	6.23
									862,500	2008				
6.75 % Series	10/5/93	*	85,000,000	85,000,000			851,022	84,148,978	-	-	6.75	*	99.00	6.82
5.95 % Series	3/23/94	4/1/01	30,000,000	30,000,000			264,883	29,735,117	-	-	5.95	6.00	99.12	6.11
6.05 % Series	3/23/94	4/1/02	25,000,000	25,000,000			224,926	24,775,074	-	-	6.05	7.00	99.10	6.19
6.15 % Series	3/23/94	4/1/03	25,000,000	25,000,000			224,926	24,775,074	-	-	6.15	8.00	99.10	6.28

(1) Date of Maturity and Average Term in Years are listed for issues with sinking fund requirements. Issues marked with an * do not have sinking fund requirements and therefore these fields are not applicable to these issues.

(2) Amount outstanding less issuance expenses net of premium.

(3) For issues without sinking fund requirements the effective cost rate is computed by dividing the nominal dividend rate by the net proceeds ratio.

(4) Includes $87,000 premium.

(5) Net proceeds after deducting $5,428,900 attributable to cost of Company refinanced issues carried forward.

Comparable Earnings Approach for Pennsylvania Power & Light Co. and the Barometer Group of Eight Electric Companies All Value Line Non-Utility Companies with Timeliness of 3, 4, and 5, Safety Ranking of 1, 2, and 3, Financial Strength of B+, B++, A and A+, Price Stability 80 and Higher, Beta's Between .55 and .75 and Technical Rank of 3 and 4.

Company Name	Industry Name	Timeliness Rank	afety Rank	Financial Strength	Price Stability	Beta	Technical Rank
ALLEGHANY CORP.	Financial Svcs	3	1	A	100	0.70	3
AMERON, INC.	Building Mat'ls	4	3	B+	90	0.55	3
AMOCO CORP.	Petro: Integr	3	1	A+	95	0.65	3
ATLANTIC R'FLD	Petro: Integr	4	2	B++	95	0.65	4
CHEVRON CORP.	Petro: Integr	4	1	A+	95	0.70	3
CINCINNATI FNCL	Insurance: P/C	4	2	B++	90	0.75	4
COMMERCIAL MTLS	Steel: General	3	2	B++	90	0.65	4
EXXON CORP.	Petro: Integr	5	2	A+	100	0.60	3
FAB INDUSTRIES	Textile	3	2	A	85	0.65	3
FLOWERS INDS	Food Processing	3	3	B+	85	0.70	3
GEICO CORP.	Insurance: P/C	3	2	A	85	0.75	3
JOSLYN CORP.	Electrical Eqp	4	2	B++	95	0.55	4
JSB FINANCIAL	Thrift	3	1	A+	90	0.70	3
LEE ENTERPRISES	Newspaper	3	2	A	90	0.75	3
MOBIL CORP.	Petro: Integr	3	1	A+	95	0.65	3
MURPHY OIL CORP	Petro: Integr	3	2	A	85	0.70	3
NASH FINCH CO.	Food Wholesale	3	3	B+	85	0.60	4
RAYTHEON CO.	Aerosp/Def	3	2	A	90	0.70	3
TENNANT CO.	Machinery	3	2	A	80	0.65	3
TEXACO INC.	Petro: Integr	4	1	A	100	0.65	3
THOMAS & BETTS	Electrical Eqp	4	2	B++	95	0.65	3
U.S. TRUST	Bank	3	2	B++	95	0.75	3
WEST CO.	Packg/Container	3	3	B+	85	0.75	3
Averages		3.4	1.9	A	91.1	0.67	3.2
Pennsylvania Power & Light Co.		4.0	2.0	B++	95.0	0.65	3.0
Barometer Group	- Average	4.0	1.9	A	99.0	0.68	4.0
	- Range	3 to 5	1 to 3	B+ to A+	95 to 100	.55 to .75	3 to 4

Source of Information: Value Line - Value Screen Data Base, October 1994

Comparable Earnings Approach
Five Year Average Historical Earned Returns
for the Years 1989-1993 and
Projected 3-5 Year Returns

Company Name	1989	1990	1991	1992	1993	Average	Projected 3-5 Year Return
ALLEGHANY CORP.	8.9%	10.6%	7.3%	8.0%	8.5%	8.7%	10.0%
AMERON, INC.	10.7%	8.1%	5.3%	5.0%	6.2%	7.1%	12.5%
AMOCO CORP.	11.8%	12.5%	8.6%	11.1%	12.8%	11.4%	16.0%
ATLANTIC R'FLD	24.7%	25.9%	14.7%	15.7%	13.3%	18.9%	17.5%
CHEVRON CORP.	10.5%	14.4%	8.8%	11.6%	13.0%	11.7%	16.0%
CINCINNATI FNCL	11.2%	12.8%	10.1%	10.0%	10.4%	10.9%	13.5%
COMMERCIAL MTLS	14.9%	12.9%	5.9%	5.9%	9.2%	9.8%	15.0%
EXXON CORP.	15.4%	15.2%	16.0%	14.2%	15.0%	15.2%	17.5%
FAB INDUSTRIES	11.2%	10.7%	14.2%	15.5%	13.7%	13.1%	12.5%
FLOWERS INDS	14.2%	15.3%	11.7%	14.5%	14.0%	13.9%	17.5%
GEICO CORP.	23.1%	19.5%	16.5%	13.4%	18.7%	18.2%	15.5%
JOSLYN CORP.	9.0%	11.6%	14.1%	15.0%	15.0%	12.9%	16.5%
JSB FINANCIAL	6.3%	3.5%	4.7%	7.9%	8.7%	6.2%	7.5%
LEE ENTERPRISES	24.4%	25.1%	17.2%	18.9%	18.5%	20.8%	20.5%
MOBIL CORP.	10.8%	11.3%	11.0%	7.9%	12.1%	10.6%	13.5%
MURPHY OIL CORP	5.5%	7.5%	4.8%	4.6%	6.3%	5.7%	10.5%
NASH FINCH CO.	8.4%	10.7%	10.7%	10.5%	8.0%	9.7%	10.0%
RAYTHEON CO.	21.8%	19.6%	17.8%	16.5%	16.1%	18.4%	15.5%
TENNANT CO.	18.2%	18.6%	15.7%	15.5%	13.9%	16.4%	16.0%
TEXACO INC.	12.9%	16.4%	12.6%	11.3%	11.0%	12.8%	13.0%
THOMAS & BETTS	16.0%	13.8%	13.3%	11.0%	11.4%	13.1%	14.5%
U.S. TRUST	17.3%	7.1%	17.2%	18.5%	18.5%	15.7%	17.0%
WEST CO.	11.5%	2.4%	8.4%	11.7%	12.0%	9.2%	13.5%
Average						12.6%	14.4%

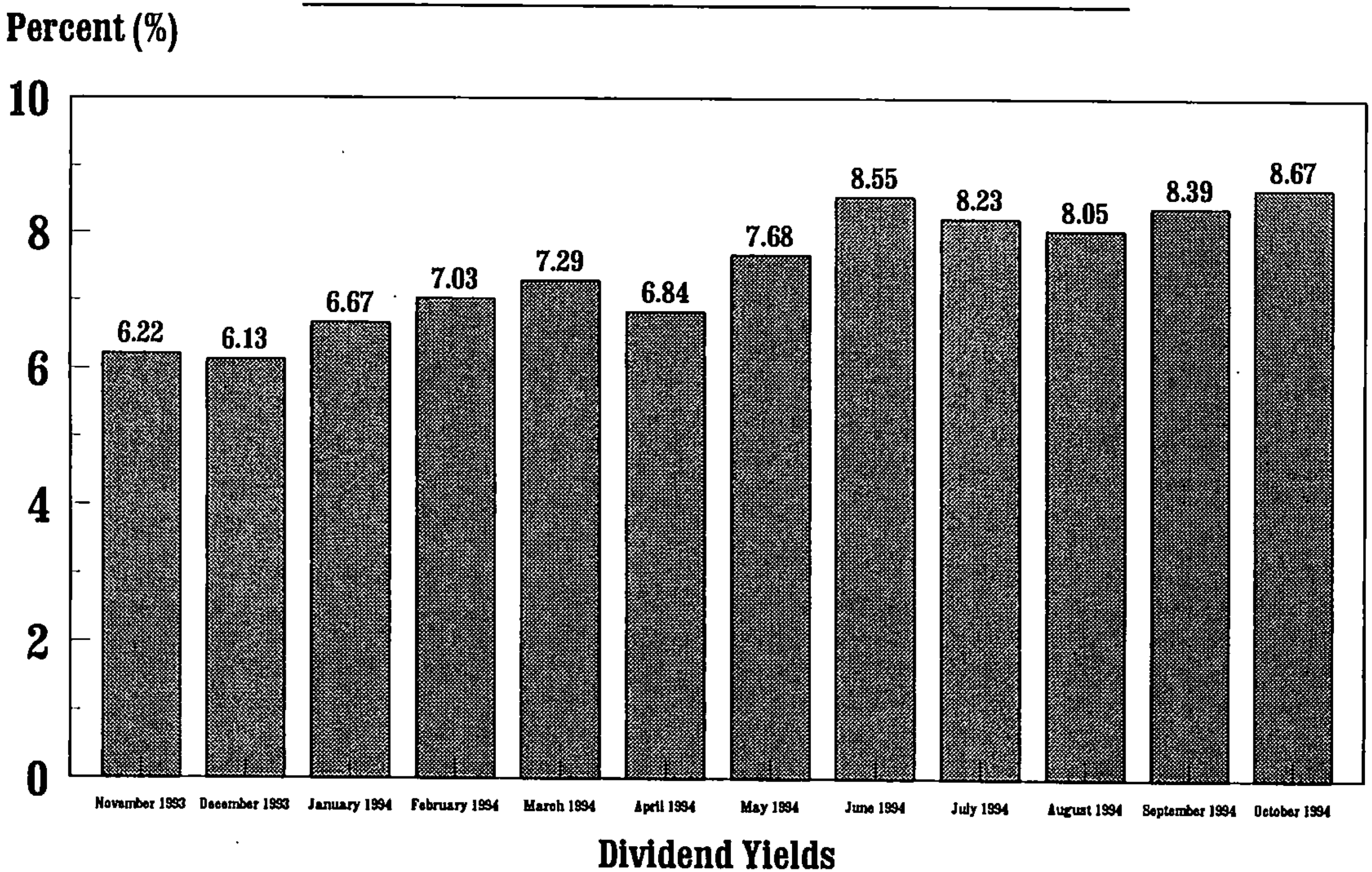
Source of Information: Value Line - Value Screen Data Base, October 1994
Value Line Investment Survey (Various Editions)

Simple DCF Results for the Comparable Earnings Group
for UGI Corp and the Barometer Group of Twelve Natural Gas Distribution Companies

Company Name	Industry Name	Dividend Yield	Projected Earnings Growth Rate	DCF Result
ALLEGHANY CORP.	Financial Svcs	0.0%	13.0%	13.0%
AMOCO CORP.	Petro: Integr	3.9%	12.5%	16.4%
ATLANTIC R'FLD	Petro: Integr	5.4%	9.0%	14.4%
CHEVRON CORP.	Petro: Integr	4.5%	13.5%	18.0%
CINCINNATI FNCL	Insurance: P/C	2.5%	15.5%	18.0%
COMMERCE BANCSH	Bank: Midwest	2.3%	8.0%	10.3%
COMMERCIAL MTLS	Steel: General	2.0%	21.5%	23.5%
EXXON CORP.	Petro: Integr	5.0%	5.0%	10.0%
HUBBELL INC 'B'	Electrical Eqp	3.1%	10.5%	13.6%
JOSLYN CORP.	Electrical Eqp	4.6%	10.0%	14.6%
JSB FINANCIAL	Thrift	3.1%	15.0%	18.1%
LEE ENTERPRISES	Newspaper	2.4%	13.5%	15.9%
MOBIL CORP.	Petro: Integr	4.5%	9.0%	13.5%
RAYTHEON CO.	Aerosp/Def	2.3%	11.5%	13.8%
TEXACO INC.	Petro: Integr	5.4%	6.0%	11.4%
THOMAS & BETTS	Electrical Eqp	3.6%	13.0%	16.6%
U.S. TRUST	Bank	3.8%	8.5%	12.3%
VULCAN MAT'LS	Cement & Aggreg	2.8%	14.5%	17.3%
Averages		3.4%	11.6%	15.0%

Source of Information: Value Line - Value Screen Data Base, October 1994

Pennsylvania Power & Light Co.
Monthly Dividend Yields
for the Twelve Months Ended October 1994

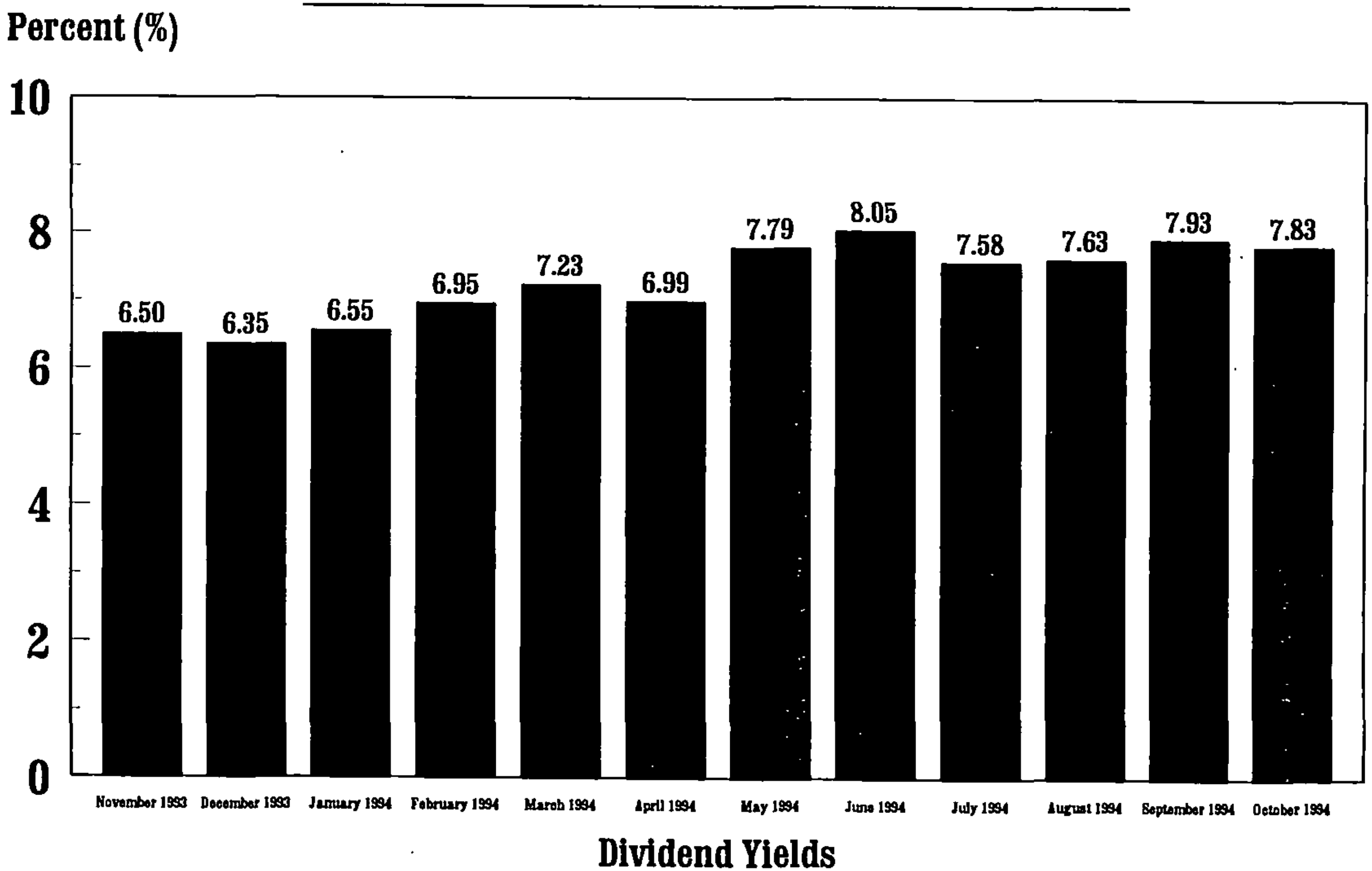


Schedule 8
Page 1 of 2

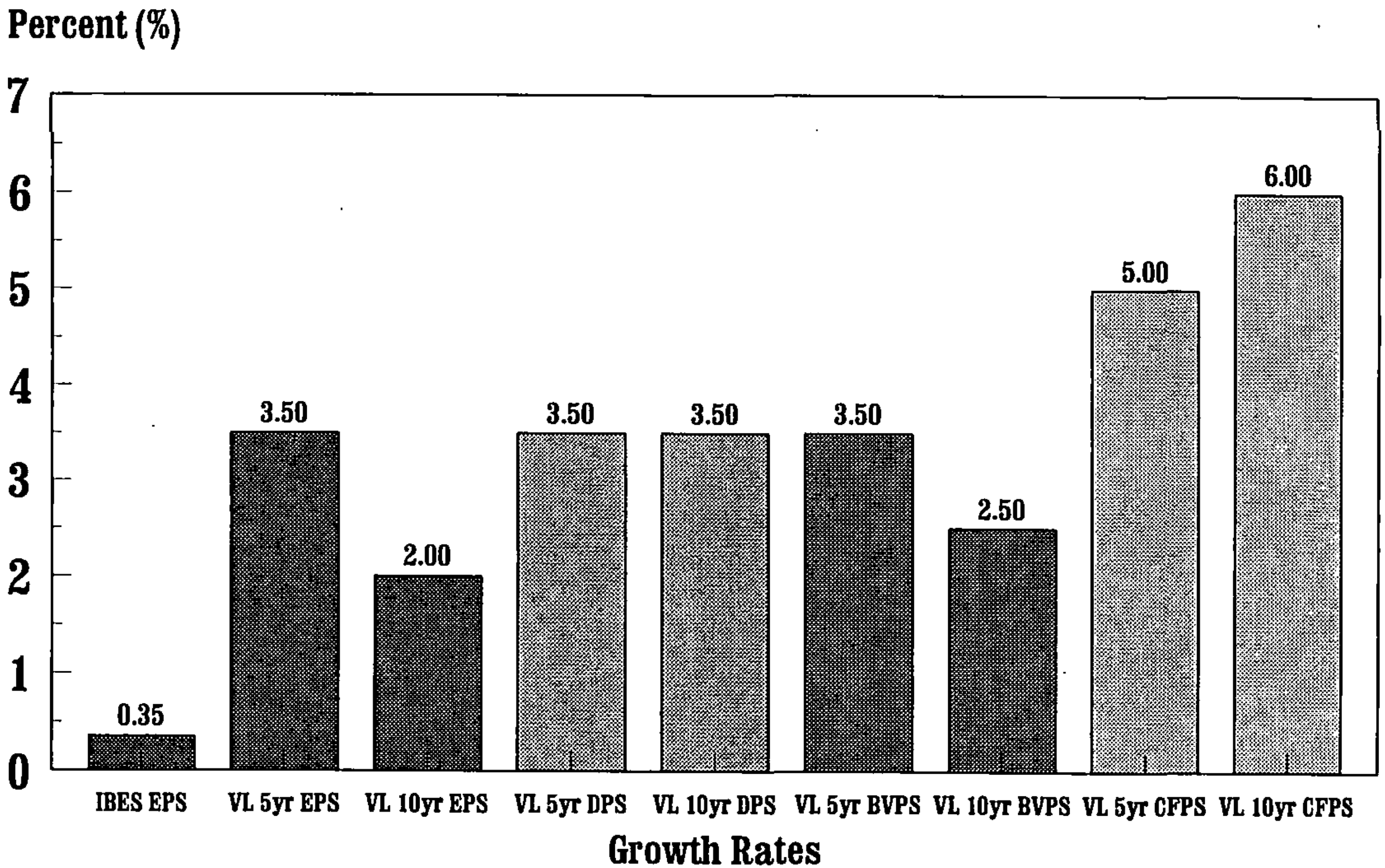
Barometer Group of Eight Electric Companies.

Monthly Dividend Yields

for the Twelve Months Ended October 1994

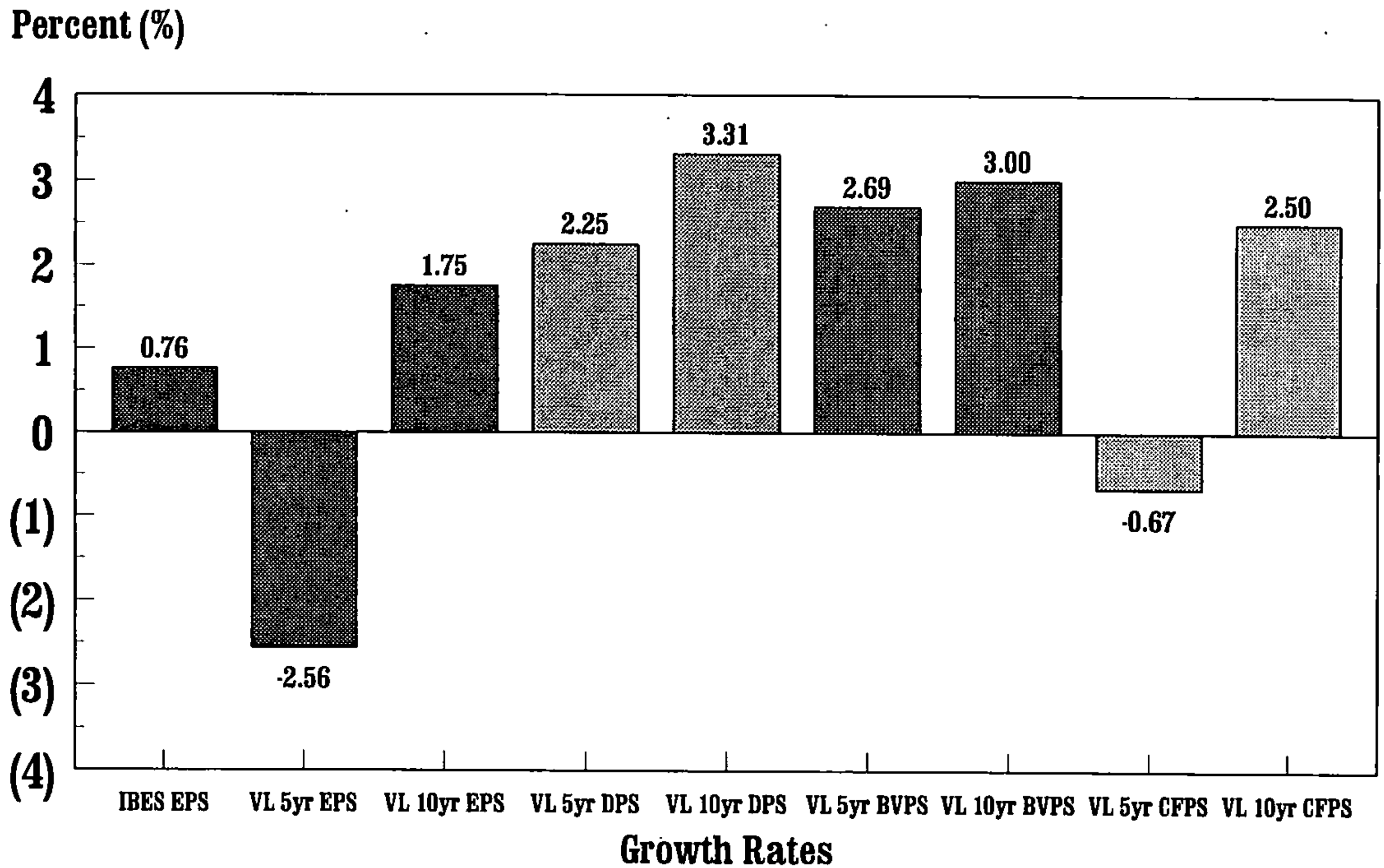


Pennsylvania Power & Light Co.
Historical Growth Rates



EPS= Earnings Per Share, DPS= Dividends Per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Barometer Group of Eight Electric Companies
Historical Growth Rates



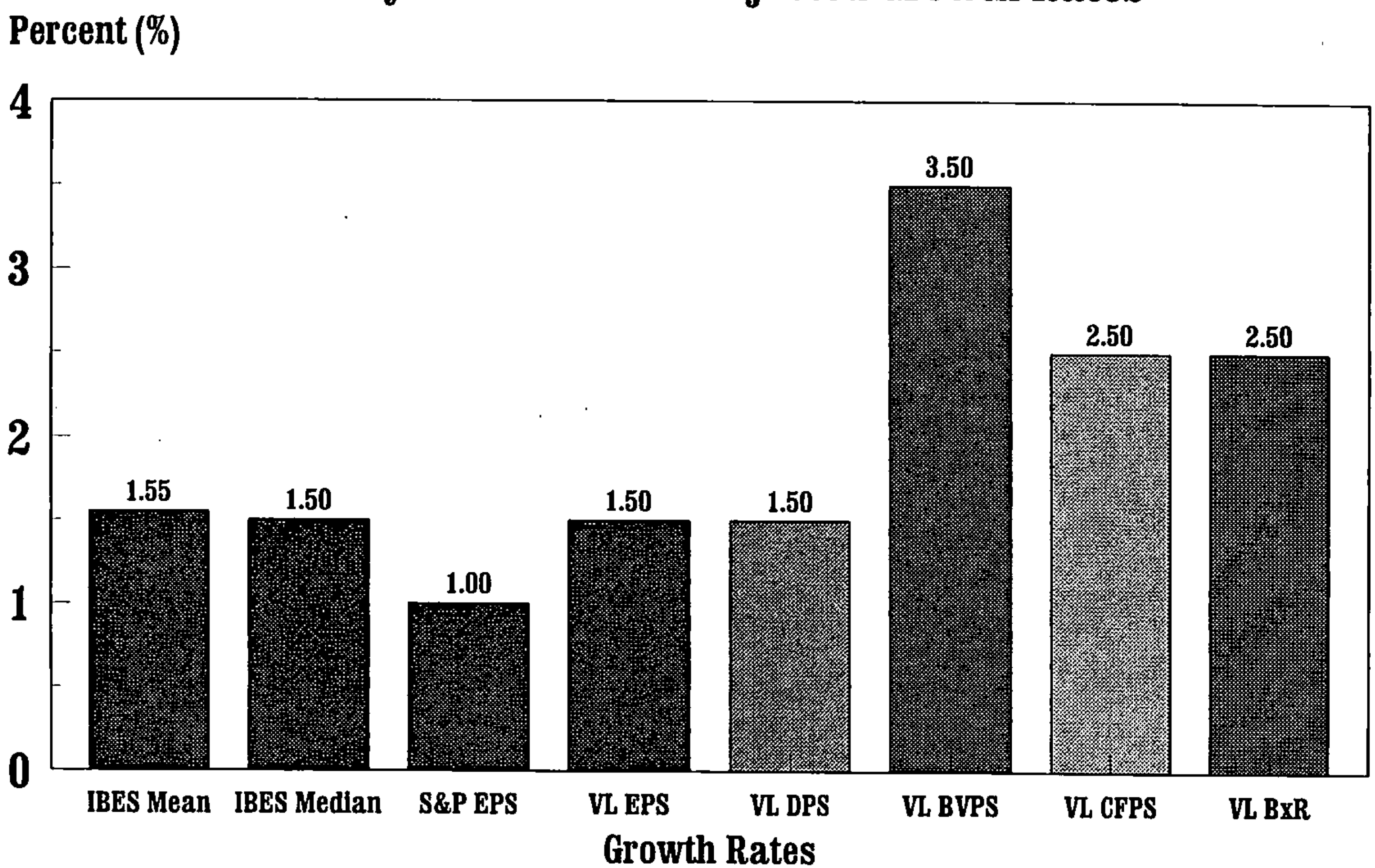
EPS= Earnings Per Share, DPS= Dividends per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Historic Internal Growth Rates
For the Years 1989-1993

	1993	1992	1991	1990	1989	Five-Year Average	Five-Year Average Excluding Negatives
Pennsylvania Power & Light Co.							
Earnings Rate on Book Common Equity	13.1%	13.1%	13.4%	13.7%	14.6%		
Dividend Rate on Book Common Equity	10.5%	10.4%	10.4%	10.3%	10.3%		
Internal Growth Rate	2.7%	2.7%	3.1%	3.3%	4.3%	3.2%	3.2%
Barometer Group of Eight							
Electric Companies							
Allegheny Power System							
Earnings Rate on Book Common Equity	11.4%	11.6%	11.7%	11.9%	12.6%		
Dividend Rate on Book Common Equity	9.9%	10.2%	10.3%	10.4%	10.5%		
Internal Growth Rate	1.5%	1.4%	-1.4%	1.5%	2.1%	1.0%	1.6%
American Electric Power							
Earnings Rate on Book Common Equity	8.4%	11.1%	11.9%	11.6%	14.6%		
Dividend Rate on Book Common Equity	10.5%	10.5%	10.6%	10.5%	10.6%		
Internal Growth Rate	-2.1%	0.6%	1.3%	1.1%	4.0%	1.0%	1.8%
Atlantic Energy Inc							
Earnings Rate on Book Common Equity	11.7%	11.1%	12.1%	10.6%	13.6%		
Dividend Rate on Book Common Equity	10.0%	10.1%	10.5%	10.3%	10.5%		
Internal Growth Rate	1.7%	1.0%	1.6%	0.3%	3.1%	1.6%	1.6%
Baltimore Gas & Electric							
Earnings Rate on Book Common Equity	10.4%	9.5%	9.0%	6.6%	12.6%		
Dividend Rate on Book Common Equity	8.3%	8.4%	8.4%	8.5%	8.5%		
Internal Growth Rate	2.1%	1.1%	0.7%	-1.9%	4.0%	1.2%	2.0%
Delmarva Power & Light							
Earnings Rate on Book Common Equity	12.6%	12.4%	11.0%	4.5%	13.4%		
Dividend Rate on Book Common Equity	11.2%	11.4%	11.9%	11.6%	11.2%		
Internal Growth Rate	1.4%	1.0%	-1.0%	-7.1%	2.1%	-0.7%	1.5%
Dpl Inc							
Earnings Rate on Book Common Equity	13.7%	13.4%	11.1%	14.8%	14.7%		
Dividend Rate on Book Common Equity	10.8%	10.7%	10.4%	10.3%	10.1%		
Internal Growth Rate	2.9%	2.7%	0.7%	4.4%	4.7%	3.1%	3.1%
Potomac Electric Power							
Earnings Rate on Book Common Equity	11.9%	10.5%	12.6%	11.3%	15.5%		
Dividend Rate on Book Common Equity	10.0%	10.2%	10.6%	10.6%	10.5%		
Internal Growth Rate	1.9%	0.4%	2.0%	0.7%	5.0%	2.0%	2.0%
Public Service Entrp							
Earnings Rate on Book Common Equity	12.0%	10.8%	12.1%	12.5%	13.4%		
Dividend Rate on Book Common Equity	10.5%	10.8%	10.6%	10.2%	10.4%		
Internal Growth Rate	1.5%	0.0%	1.5%	2.3%	2.9%	1.6%	1.6%
Average							
Earnings Rate on Book Common Equity	11.5%	11.3%	11.4%	10.5%	13.8%		
Dividend Rate on Book Common Equity	10.2%	10.3%	10.4%	10.3%	10.3%		
Internal Growth Rate	1.4%	1.0%	1.0%	0.2%	3.5%	1.3%	1.9%

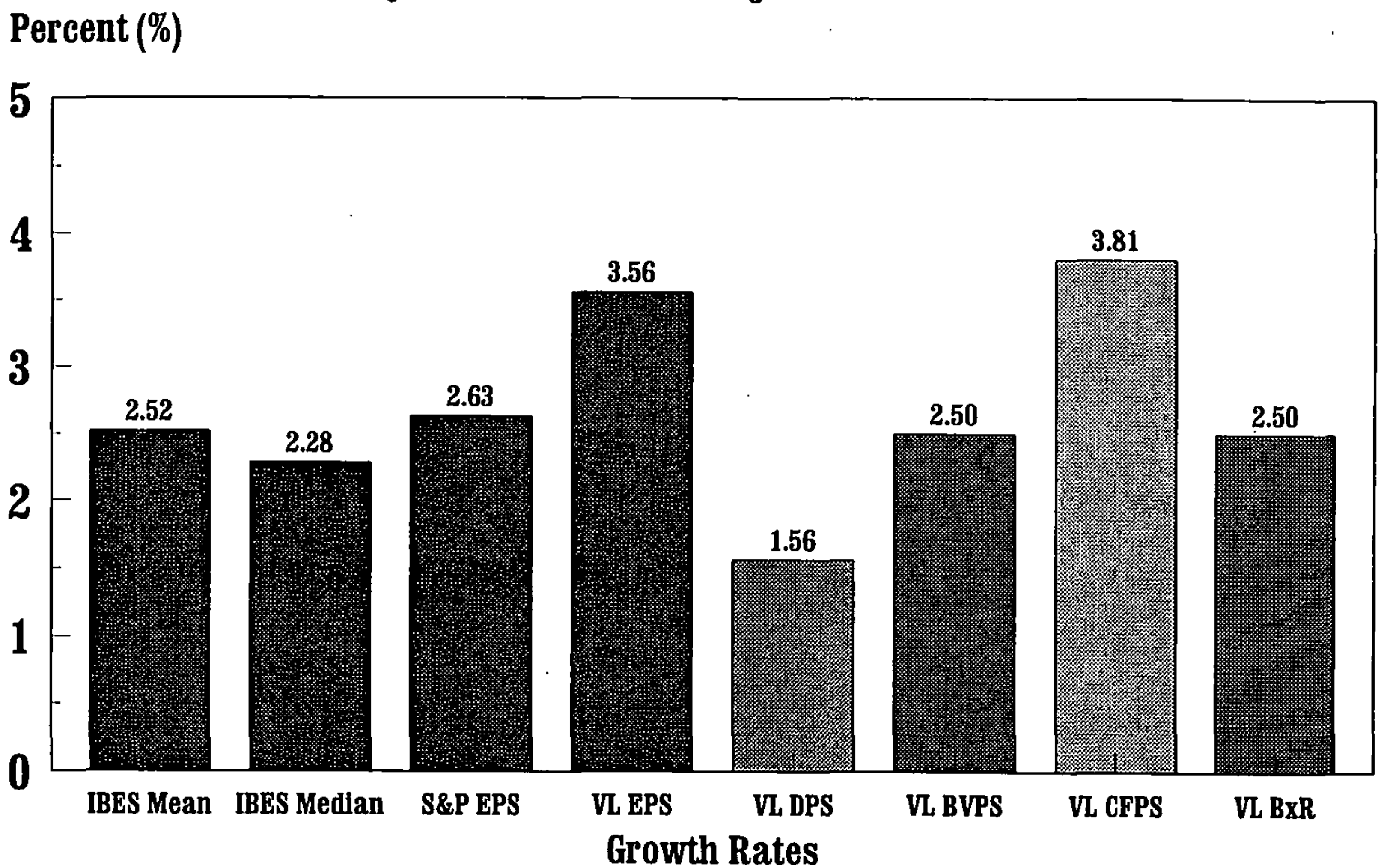
Source of Information : OneSource
Standard & Poor's Utility Compustat

Pennsylvania Power & Light Co.
Analysts' Five-Year Projected Growth Rates



EPS= Earnings Per Share, DPS= Dividends Per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Barometer Group of Eight Electric Companies
Analysts' Five-Year Projected Growth Rates

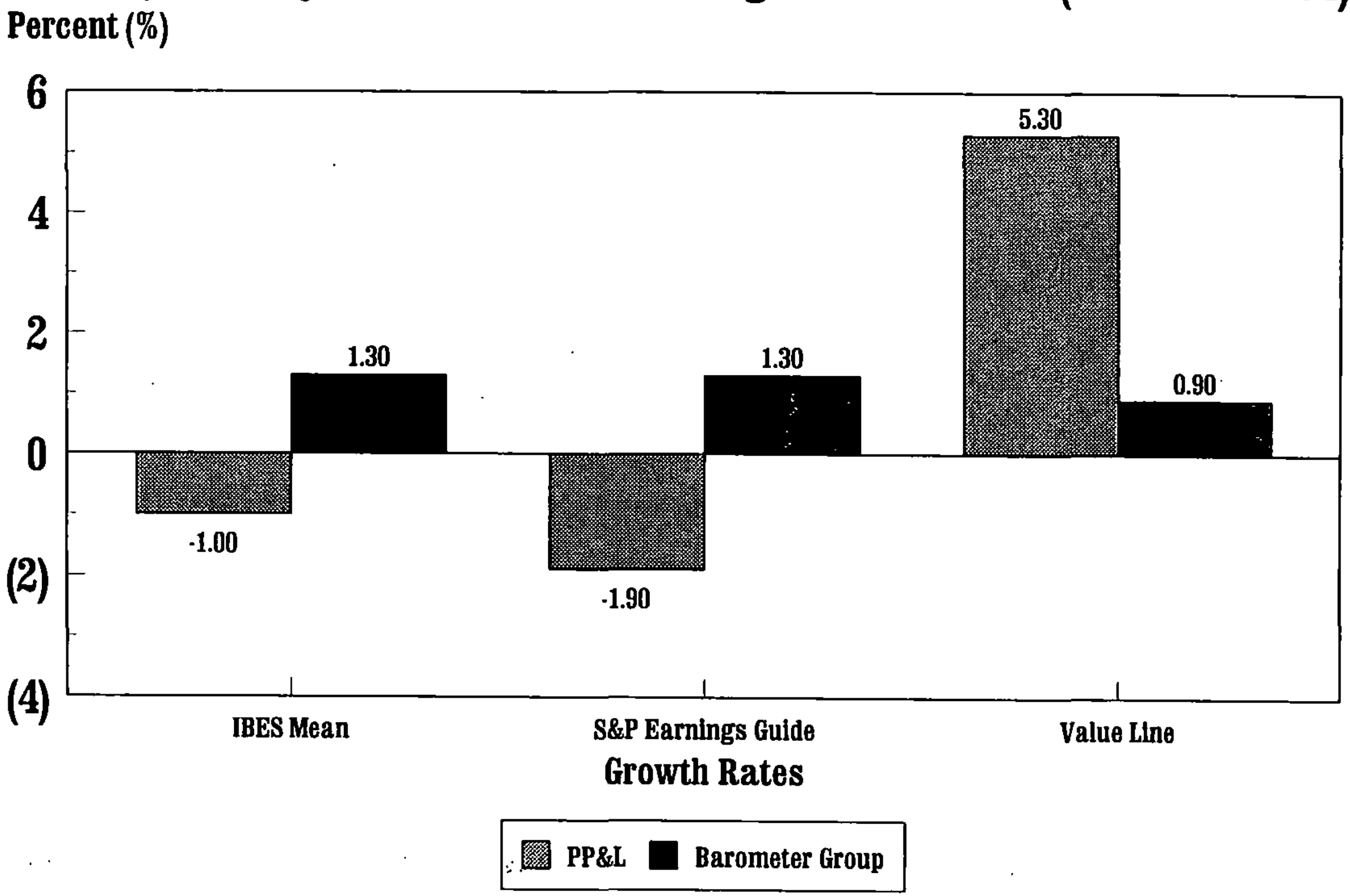


EPS= Earnings Per Share, DPS= Dividends Per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

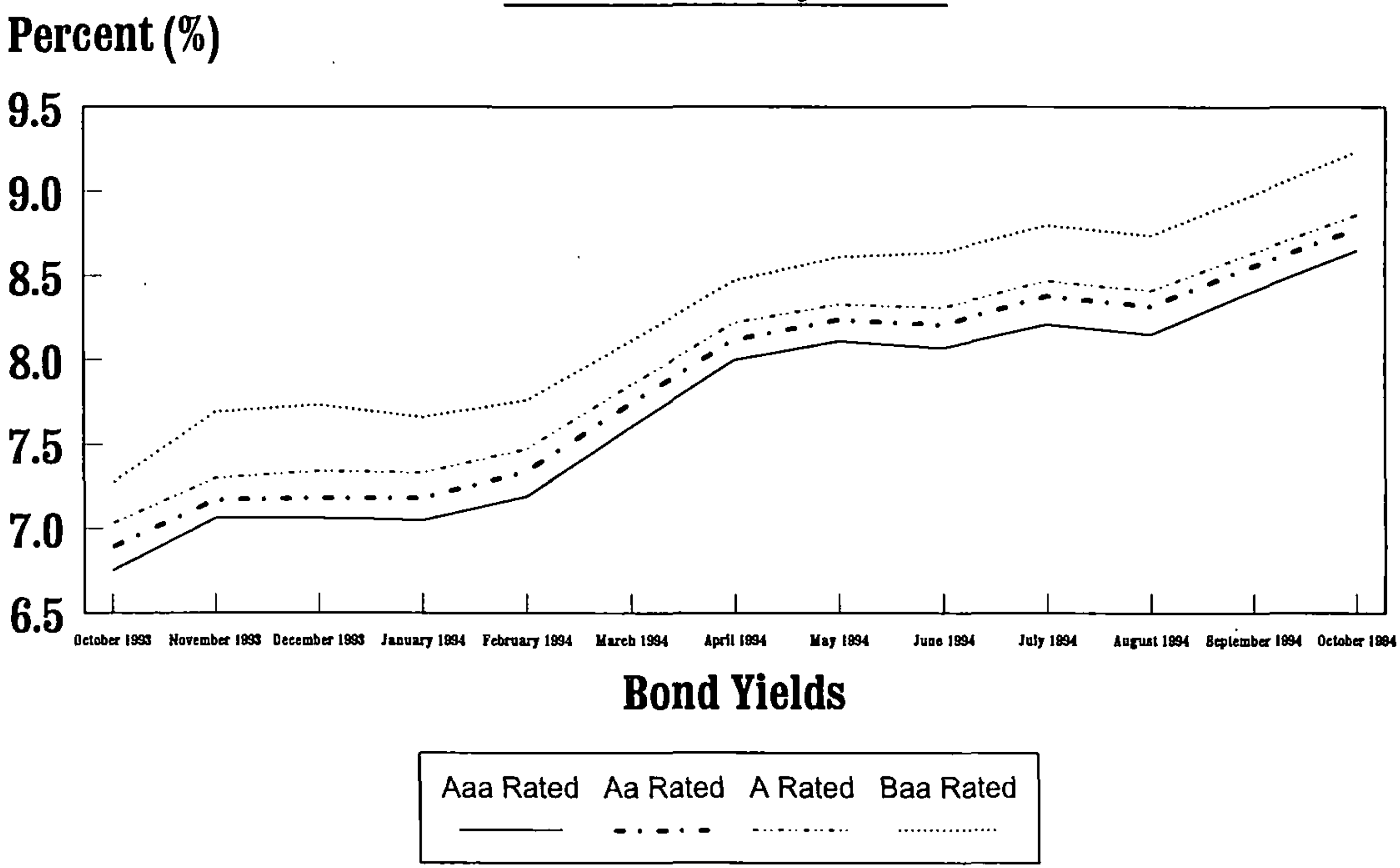
Pennsylvania Power & Light Co.

and the Barometer Group of Eight Electric Companies

Analysts' Projected Short-Run Earnings Growth Rates (1995 over 1994)



Pennsylvania Power & Light Co.
Interest Rate Trends
for Public Utility Bonds



Interest Rate Trends for Investor-Owned Public Utility Bonds
Yearly for 1989-1993
and the Twelve Months Ended October 1994

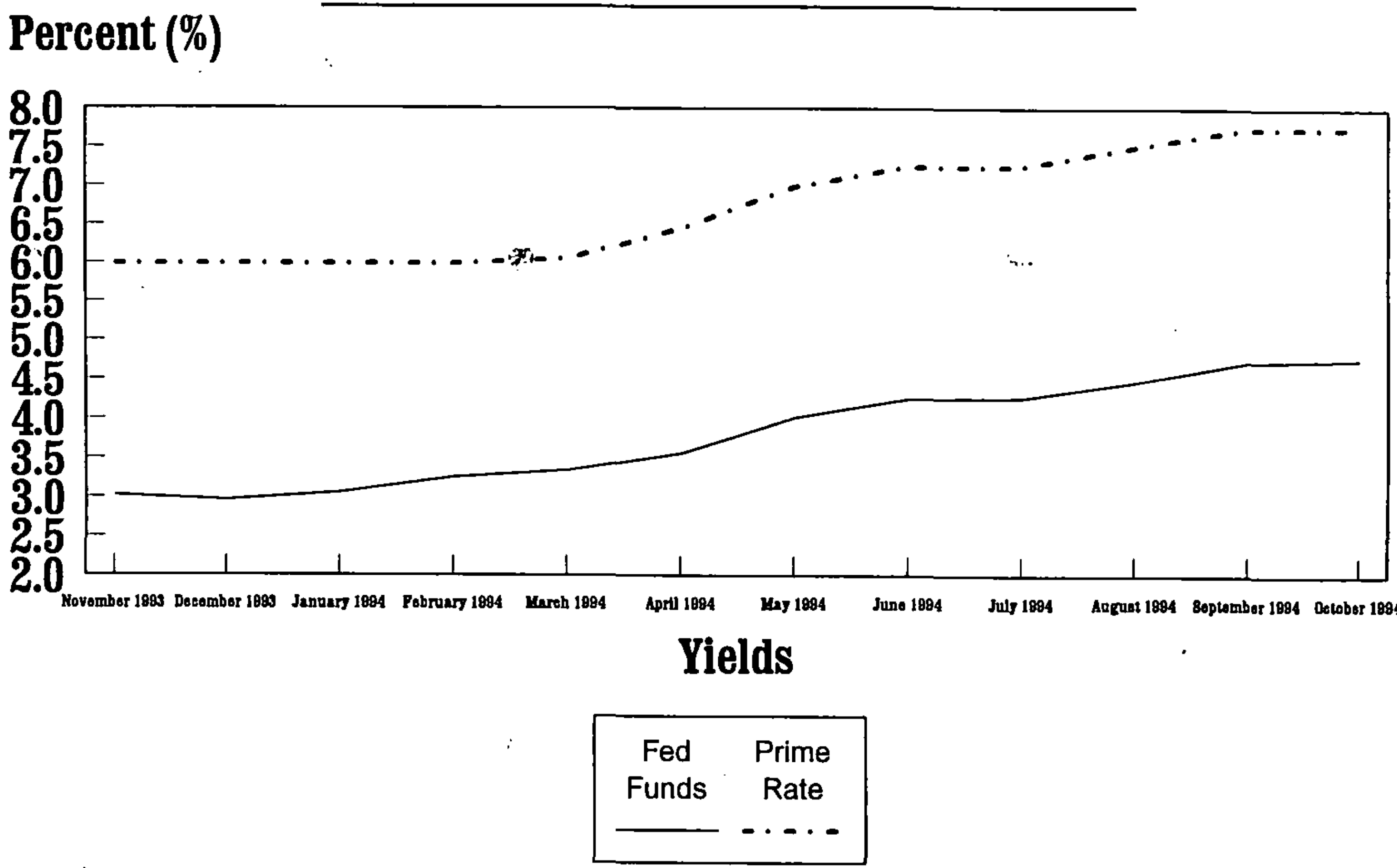
Years	Aaa Rated	Aa Rated	A Rated	Baa Rated	Average
1989	9.32%	9.56%	9.77%	9.97%	9.66%
1990	9.45%	9.66%	9.86%	10.06%	9.76%
1991	8.85%	9.09%	9.36%	9.55%	9.21%
1992	8.19%	8.55%	8.69%	8.86%	8.57%
1993	7.29%	7.44%	7.59%	7.91%	7.56%
Twelve Month Average	7.80%	7.94%	8.04%	8.37%	8.04%

Source of Information : Moody's Investors Services, Inc. (Public Utility Manuals and Bond Surveys)

Pennsylvania Power & Light Co.

Money Cost Rates

for the Twelve Months ended October 1994



**S & P Composite Index, S & P Industrial Index,
S & P Public Utility Index,
Long-Term Corporate and Public Utility Bonds
Year-by Year Total Returns
1928-1993**

Year	S & P Composite Index	S & P Industrial Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	0.4381	0.4512	0.5747	0.0284	0.0308
1929	-0.0842	-0.1550	0.1102	0.0327	0.0234
1930	-0.2490	-0.2645	-0.2196	0.0798	0.0474
1931	-0.4334	-0.4325	-0.3590	-0.0185	-0.1111
1932	-0.0819	-0.1118	-0.0054	0.1082	0.0725
1933	0.5399	0.8615	-0.2187	0.1038	-0.0382
1934	-0.0144	0.0187	-0.2041	0.1384	0.2281
1935	0.4767	0.4500	0.7663	0.0961	0.1603
1936	0.3392	0.3364	0.2069	0.0674	0.0830
1937	-0.3503	-0.3471	-0.3704	0.0275	-0.0405
1938	0.3112	0.3398	0.2245	0.0613	0.0811
1939	-0.0041	-0.0318	0.1126	0.0397	0.0678
1940	-0.0978	-0.0995	-0.1715	0.0339	0.0445
1941	-0.1159	-0.0949	-0.3157	0.0273	0.0215
1942	0.2034	0.2133	0.1539	0.0260	0.0381
1943	0.2590	0.2256	0.4607	0.0283	0.0704
1944	0.1975	0.1777	0.1803	0.0473	0.0329
1945	0.3644	0.3401	0.5333	0.0408	0.0592
1946	-0.0807	-0.0874	0.0126	0.0172	0.0298
1947	0.0571	0.0806	-0.1316	-0.0234	-0.0219
1948	0.0550	0.0519	0.0401	0.0414	0.0265
1949	0.1879	0.1652	0.3139	0.0331	0.0716
1950	0.3171	0.3333	0.0325	0.0212	0.0201
1951	0.2402	0.2531	0.1863	-0.0269	-0.0277
1952	0.1837	0.1760	0.1925	0.0352	0.0299
1953	-0.0099	-0.0193	0.0785	0.0341	0.0208
1954	0.5262	0.5716	0.2472	0.0539	0.0757
1955	0.3156	0.3528	0.1126	0.0048	0.0012
1956	0.0656	0.0756	0.0506	-0.0681	-0.0625
1957	-0.1078	-0.1076	0.0636	0.0871	0.0358
1958	0.4336	0.4295	0.4070	-0.0222	0.0018
1959	0.1195	0.1280	0.0749	-0.0097	-0.0229
1960	0.0047	-0.0140	0.2026	0.0907	0.0901
1961	0.2689	0.2674	0.2933	0.0482	0.0465
1962	-0.0873	-0.0986	-0.0244	0.0795	0.0655
1963	0.2280	0.2386	0.1236	0.0219	0.0344
1964	0.1648	0.1646	0.1591	0.0477	0.0494
1965	0.1245	0.1313	0.0467	-0.0046	0.0050
1966	-0.1006	-0.1049	-0.0448	0.0020	-0.0345
1967	0.2398	0.2714	-0.0063	-0.0495	-0.0363
1968	0.1106	0.1071	0.1032	0.0257	0.0187
1969	-0.0850	-0.0740	-0.1542	-0.0809	-0.0666
1970	0.0401	0.0307	0.1656	0.1837	0.1590
1971	0.1431	0.1504	0.0241	0.1101	0.1159
1972	0.1898	0.2006	0.0815	0.0726	0.0719
1973	-0.1466	-0.1487	-0.1807	0.0114	0.0242
1974	-0.2647	-0.2693	-0.2155	-0.0306	-0.0528
1975	0.3720	0.3717	0.4449	0.1464	0.1550
1976	0.2384	0.2257	0.3181	0.1865	0.1904
1977	-0.0718	-0.0835	0.0864	0.0171	0.0522
1978	0.0656	0.0772	-0.0371	-0.0007	-0.0098
1979	0.1844	0.1887	0.1358	-0.0418	-0.0275
1980	0.3242	0.3403	0.1508	-0.0262	-0.0023
1981	-0.0491	-0.0677	0.1174	-0.0096	0.0427
1982	0.2141	0.2138	0.2652	0.4379	0.3352
1983	0.2251	0.2301	0.2001	0.0470	0.1033
1984	0.0627	0.0420	0.2604	0.1639	0.1482
1985	0.3216	0.3062	0.3305	0.3090	0.2648
1986	0.1847	0.1865	0.2853	0.1985	0.1816
1987	0.0523	0.0873	-0.0292	-0.0027	0.0302
1988	0.1681	0.1593	0.1827	0.1070	0.1019
1989	0.3149	0.2939	0.4780	0.1623	0.1561
1990	-0.0317	-0.0089	-0.0257	0.0678	0.0813
1991	0.3055	0.3076	0.1461	0.1989	0.1925
1992	0.0767	0.0573	0.0811	0.0939	0.0866
1993	0.0999	0.0911	0.1442	0.1319	0.1060
Geometric Mean Return	9.94%	10.09%	8.78%	5.53%	5.35%
Arithmetic Mean Return	11.95%	12.35%	10.98%	5.85%	5.65%
Standard Deviation	20.53%	22.27%	21.97%	8.58%	8.12%
Median Return	13.38%	14.09%	11.26%	3.75%	4.36%

Source of Information : Ibbotson & Associates
Standard & Poor's Security Price Index Record

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-1993, 1952-1993, 1974-1993 and 1979-1993

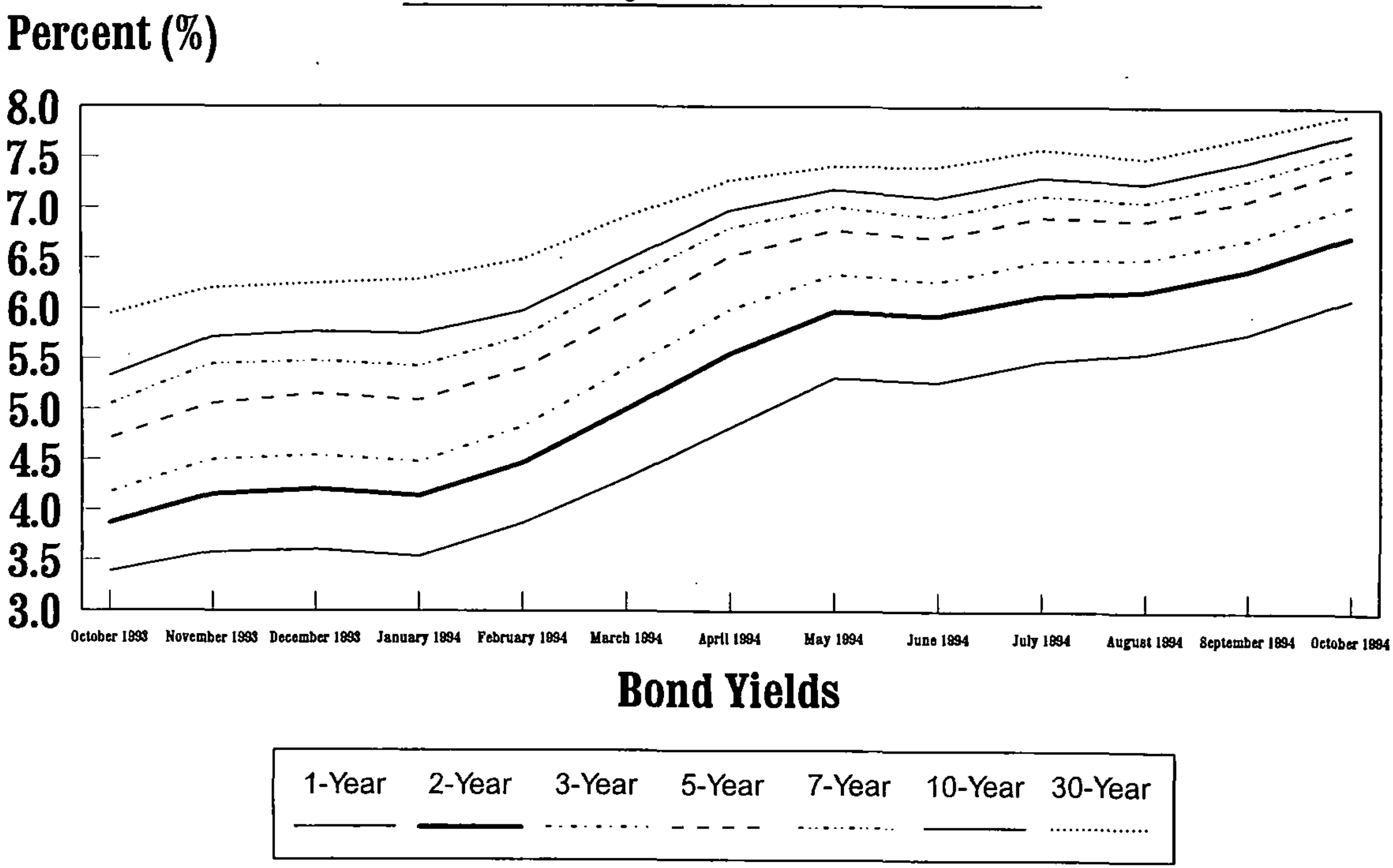
Total Returns	Range: Geometric Mean	Range: Median	Range: Midpoint	Point Estimate Arithmetic Mean	Average of Midpoint and Point Estimate
1928-1993					
S&P Public Utility Index	8.78%	11.26%		10.98%	
Public Utility Bonds	5.35	4.36		5.65	
Risk Differential	3.43%	6.90%	5.17%	5.33%	5.25%
1952-1993					
S&P Public Utility Index	11.65%	12.05%		12.70%	
Public Utility Bonds	6.23	4.80		6.57	
Risk Differential	5.42%	7.25%	6.34%	6.13%	6.24%
1974-1993					
S&P Public Utility Index	15.39%	14.85%		16.60%	
Public Utility Bonds	10.26	10.26		10.68	
Risk Differential	5.13%	4.59%	4.86%	5.92%	5.39%
1979-1993					
S&P Public Utility Index	17.48%	15.08%		18.15%	
Public Utility Bonds	11.62	10.33		12.00	
Risk Differential	5.86%	4.75%	5.31%	6.15%	5.73%

Merrill Lynch and Value Line
Adjusted Betas for Pennsylvania Power & Light Co. and the
Barometer Group of Eight Electric Companies

	Merrill Lynch Adjusted Beta	Value Line Adjusted Beta	Average Adjusted Beta
Pennsylvania Power & Light Co.	0.74	0.65	0.70
Barometer Group of Eight Electric Companies			
Allegheny Power System	0.62	0.65	0.64
American Electric Power	0.76	0.75	0.76
Atlantic Energy Inc	0.66	0.70	0.68
Baltimore Gas & Electric	0.74	0.75	0.75
Delmarva Power & Light	0.57	0.65	0.61
Dpl Inc	0.56	0.55	0.56
Potomac Electric Power	0.74	0.70	0.72
Public Service Entrp	0.75	0.70	0.73
Average	0.68	0.68	0.68

Source of Information : Merrill Lynch Security Price Index, July 1994
Value Line Investment Survey, September 16, 1994 and October 14, 1994

Pennsylvania Power & Light Co.
Interest Rate Trends
for Treasury Constant Maturities



Interest Rate Trends for Treasury Constant Maturities
Yearly for 1989-1993
and the Twelve Months Ended October 1994

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	30-Year
1989	8.53%	8.57%	8.55%	8.50%	8.52%	8.49%	8.45%
1990	7.88%	8.16%	8.25%	8.37%	8.52%	8.54%	8.61%
1991	5.86%	6.49%	6.81%	7.37%	7.68%	7.86%	8.14%
1992	3.89%	4.77%	5.31%	6.19%	6.63%	7.01%	7.67%
1993	3.43%	4.05%	4.44%	5.15%	5.55%	5.87%	6.60%
Twelve Month Average	4.77%	5.41%	5.76%	6.24%	6.51%	6.72%	7.08%

Source of Information : Federal Reserve Statistical Release

Measures of the Risk Free Rate
Using Blue Chip Financial Forecasts

The forecast 30-year Treasury Bond yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated November 1, 1994.

	Treasury Note Yield 10-Year	Treasury Bond Yield 30-Year
Fourth Quarter 1994	7.9%	8.1%
First Quarter 1995	8.1	8.2
Second Quarter 1995	8.1	8.2
Third Quarter 1995	8.0	8.2
Fourth Quarter 1995	8.0	8.1

ource of Infomation: Blue Chip Financial Forecasts, December 1, 1994

THE VALUE LINE® Investment Survey

Part 1 Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

November 18, 1994

TABLE OF SUMMARY-INDEX CONTENTS

Summary-Index Page Number

SCREENS

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

14.5

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
15.2	4.8	16.9

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

2.6%

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
2.6%	7.8%	2.3%

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

70%

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
70%	234%	40%

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

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

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

*Reviewed in this week's edition.

In three parts: This is Part 1, the *Summary & Index*. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume L, No. 10.
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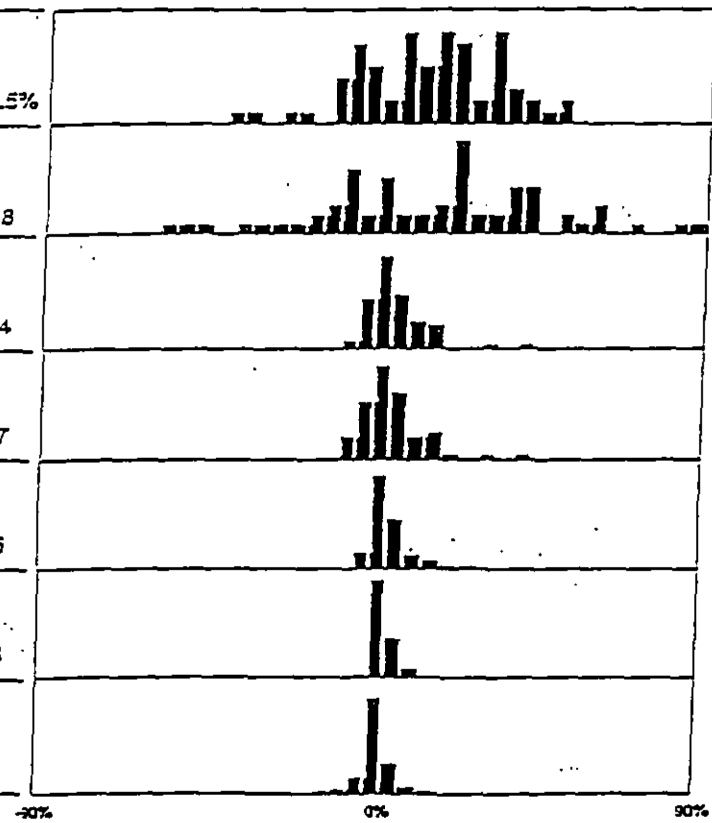
Exhibit 9 **Basic Series: Summary Statistics of Annual Total Returns**

Schedule 13
Page 6 of 6

From 1926 to 1993

Series	Geometric Mean	Arithmetic Mean	Standard Deviation
Large Company Stocks	10.3%	12.3%	20.5%
Small Company Stocks	12.4	17.5	34.8
Long-Term Corporate Bonds	5.6	5.9	8.4
Long-Term Government Bonds	5.0	5.4	8.7
Intermediate-Term Government Bonds	5.3	5.4	5.6
U.S. Treasury Bills	3.7	3.7	3.3
Inflation	3.1	3.2	4.6

Distribution



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

Pennsylvania Power & Light Co.
Cost of Capital and Fair Rate of Return
Estimated at September 30, 1995

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.53%	7.97%	3.71%
Preferred Stock	7.59%	7.31%	0.55%
Common Equity	45.88%	13.00%	5.96%
Overall Cost of Capital	100.00%		10.22%

Indicated level of fixed coverage assuming the Company could actually achieve a 10.22% overall rate of return.

Before-income tax coverage of interest expense based upon a 42.1435% effective federal and state income tax rate. (14.96% / 3.71%)	4.03x
After-income tax coverage of interest expense (10.22% / 3.71%)	2.75x
Overall coverage of interest expense and preferred stock dividends (10.22% / 4.26%)	2.40x

PENNSYLVANIA POWER & LIGHT COMPANY

Direct Testimony
Statements 12-14

Docket No. R-00943271

Pennsylvania Power & Light Company
Docket No. R-00943271
Index of Direct Testimony

Company Witnesses	Nature of Testimony	Statement	Exhibit
Ronald E. Hill	- Overall Rate Philosophy - Management Effectiveness - Financing Plans - Investment of Nuclear Decommissioning Reserve Fund	1	—
Michael J. Berish	- Operating Budgets - Voluntary Early Retirement Program - SFAS 106 Cost Containment	2	MJB 1-8
Ronald J. Bernini	- Expense Adjustments - Taxes - Cash Working Capital - Fuel Inventories and Reserves - Decommissioning Annuities - Early Window Costs	3	—
Donald S. Hoch	- Depreciation - Levelized Sinking Fund Depreciation	4	DSH 1-2
Douglas A. Krall	- Capital Budget - Pollution Control CWIP - Fossil Plant Lives - Coal Upgrading	5	DAK 1-4
John J. Slivka	- Sales and Peak Demand Forecasts - Annualization of Sales and Revenue - Load Research	6	JJS 1
Joseph M. Kleha	- Cost Allocation - Energy Cost Rate - Special Base Rate Credit Adjustment - Property Held for Future Use	7	JMK 1-3
Oliver G. Kasper	- Pro Forma Revenue Adjustments - Class Revenue Allocation - Rate Design - Proof of Revenues	8	OJK 1-4

Company Witnesses	Nature of Testimony	Statement	Exhibit
John F. Sipics	- Electrical System - Capacity Planning and Reserve Margins - Value of Interruptible Load	9	JFS 1-2
Gerald S. Farber	- Economic Development - Demand-Side Management - Energy Efficiency	10	—
Bernard J. Bujnowski	- Customer and Community Needs Programs	11	—
Paul R. Moul	- Cost of Common Equity - Fair Rate of Return - Capital Structure - Embedded Capital Cost Rates	12	PRM 1
Thomas S. LaGuardia	- Nuclear Plant Decommissioning - Fossil Plant Decommissioning	13	TSL 1-2
Clyde D. Beers	- SFAS 106 Costs	14	CDB 1

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 12

Direct Testimony of Paul R. Moul

Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY

Direct Testimony

of

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

Concerning

Fair Rate of Return

Pennsylvania Power & Light Company
Direct Testimony of Paul R. Moul
Table of Contents

DIRECT TESTIMONY OF PAUL R. MOUL

Introduction and Summary of Recommendations

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

A. My name is Paul Ronald Moul. My business address is 1101 Kings Highway North, Cherry Hill, New Jersey, and my mailing address is P.O. Box 8207, Cherry Hill, New Jersey 08002. I am Managing Consultant of the firm P. Moul & Associates, an independent public utility consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate cost of capital and fair rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should allow Pennsylvania Power & Light Company ("PP&L" or the "Company") an opportunity to earn on its rate base devoted to public service. Additional evidence, in the form of appendices, follows my direct testimony. My analysis and recommendation are supported by the detailed financial data set forth in my Exhibit PRM-1 which consists of fourteen (14) schedules.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn a 10.22% overall rate of return which includes a 13.00% rate of return on common equity. My 13.00% rate of return on common equity is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital, for the Company. My overall rate of return recommendation is determined by using the weighted average cost of capital. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall fair rate of return when applied to the Company's rate base will provide a level of return which will compensate investors for the use of their capital.

My overall cost of capital recommendation is set forth below and is shown on Schedule 14.

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

This overall rate of return is applicable to the September 30, 1995 future test year and the period that the Company's proposed rates will be effective.

Q. What factors have you considered in the determination of the Company's cost of equity in this proceeding?

A. The Company is an operating electric utility which provides service to approximately 1,203,000 customers in twenty-nine central eastern Pennsylvania counties. The Company operates its generation and transmission facilities as part of the PJM interconnection. The common stock of PP&L is listed and traded on the New York Stock Exchange (as well as other regional exchanges). The Company is in the process of forming a holding company in order to position itself for the additional competition which will develop as a result of the Energy Policy Act of 1992. The new holding company, which will be known as PP&L Resources, Inc., will have PP&L as a wholly-owned subsidiary along with Power Markets Development Company which will invest in non-regulated power-related businesses. After the formation of the holding company, PP&L will continue to dominate the operations of PP&L Resources. Further, the long-term debt and preferred stock previously issued by PP&L will continue to be an obligation of the Company. PP&L will continue to sell its long-term debt and preferred stock directly in the capital markets.

Q. How have you determined the cost of equity to be used as a component of the Company's overall cost of capital?

A. In arriving at a 13.00% cost of equity, I have relied on four well recognized measures: the Comparable Earnings approach, the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, and the Capital Asset Pricing Model ("CAPM"). By considering the results of a variety of approaches, I determined that 13.00% represents a reasonable cost of equity applicable to an original cost rate base which is consistent with the well recognized principles for determining a fair rate of return. The models which I used to measure the cost of equity for the Company have been applied with market data developed from PP&L and a Barometer Group of Eight Electric Companies (the "Barometer Group").

Q. In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A. It is important that the Commission consider the end result of its rate of return determination. In this regard, the rate of return must provide a reasonable level of earnings retention (i.e., produce an adequate level of internally generated funds to meet capital requirements), support reasonable credit quality, and be commensurate with the risk to which the Company's invested capital is exposed. The Company must have the financial strength characteristics which will permit it to maintain its current credit quality rating from Standard & Poor's Corporation ("S&P") and from Moody's Investors Service, Inc. ("Moody's"). Mr. Hill's testimony describes the Company's recent efforts to sustain its bond ratings. In spite of these efforts, the Company suffered a downgrading in its rating during the historic test year.

I therefore tested what I determined to be the Company's overall cost of capital in this case by reference to fixed charge coverage in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. It is important that the Commission provide the Company with a reasonable opportunity to generate an adequate level of pre-tax interest coverage so that the Company's financial condition is commensurate with its public service obligation. I have concluded that the Company's overall rate of return request in this case is necessary and appropriate to meet its fixed charges and to satisfy the capital attraction and maintenance of credit standards of a fair rate of return.

<u>Ratesetting Principles</u>

Q. What accepted regulatory principles govern the determination of a fair rate of return on common equity?

A. Insofar as tariffed rates are concerned, the Commission serves as a substitute for competition and sets the price for service. In setting rates, the Commission must carefully consider the public's interest in reasonably priced, as well as safe and reliable service. While rates must take into account the interests of consumers, they must also allow a rate of return to the utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the utility has access to the capital required to meet its public service responsibility. Without an opportunity to earn a fair rate of return, the utility will be unable to attract the capital required to meet its obligation to provide service to the public.

In this regard, it is important to remember that regulated firms must compete with non-regulated firms, as well as municipal, state and federal governments, in a global market for capital. Unlike a competitive firm, a public utility has the obligation under its franchise to provide a particular type of service in a specific geographic area. In contrast, a non-regulated firm is free to enter and exit competitive markets as circumstances warrant. Such a situation would not be appropriate for public utilities since reliability of service is essential to the public interest.

As established by the landmark Bluefield and Hope cases,[1] several tests must be satisfied to demonstrate the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to

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[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).

that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public. A fair rate of return must not only provide the utility with the ability to attract new capital, but must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings. My recommendation meets these standards and represents a fair rate of return for the Company in this case.

Evaluation of Risk

Q. How does the risk of a firm impact its cost of capital?

A. The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk. Since investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required market-determined cost of capital if utilities are to attract the necessary investment capital on reasonable terms.

Q. How is risk analyzed for a firm?

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

Q. What are the components which comprise the investment risk of a firm?

A. The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk. It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated public utilities than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, public utilities bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Q. Are there procedures for evaluating the relative risk of different enterprises?

A. Yes. Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

<u>Electric Utility Risk Factors</u>

Q. Please identify some of the risk factors which make the electric utility industry different today from its past.

A. Today, electric utilities are faced with meaningful changes in fundamentals, while cost of service pricing continues to dominate their business profile. Aside from their traditional responsibility to supply adequate capacity to meet forecast loads (in a more uncertain market), and to comply with increasingly stringent environmental standards, additional competitive risks are now evolving in a new era for electric utilities. These risks include competition from alternative energy sources and competition from other utilities and non-utilities. Sometimes this situation is referred to as the risk of self generation and/or the risk of bypass. With the evolution of cogeneration as an alternative source of energy, as well as energy available from independent power producers, the loss of revenues from existing customers which obtain energy from alternative sources is particularly onerous as compared with a new electric user providing its own generating capacity. When customers engage in either self-generation or bypass of a utility's integrated system, the electric utility is faced with the prospect of losses occasioned by stranded investment and unrecovered costs. With increased emphasis on market-determined prices and competition in the electric generation market and the trend toward open access of the transmission network (e.g., the National Energy Policy Act of 1992), an entirely new dimension has been opened in the electric utility business. However, pricing policies of public utilities are restrained by regulation, while other non-regulated firms have greater latitude in adjusting their prices and responding to changing market conditions. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition. Hence, partial deregulation of electric utilities provides significant downside risk due to loss of revenues, but provides little upside potential due to the limitations placed on returns by regulators.

In addition, there is particular concern in today's economic environment regarding the economic vitality of a utility's service territory. Increasingly, reliance upon supportive rate case decisions has become an important determinant of the financial condition of a utility in the absence of revenue growth associated with increased sales. That is to say, some electric utilities will become more dependent upon rate increases during a period of moderating growth, rather than sales growth which previously provided a means to deal with higher costs.

Further, with the passage of the Clean Air Act Amendments ("CAAA"), many electric utilities will face substantial increases in operating and capital costs to comply with the new air quality standards. Other new risks include the trend toward performance regulation, demand side management, increased productivity demands, and emphasis upon high levels of customer service. These business and regulatory risks all bear upon investor perception concerning risk and the required rate of return for electric utilities.

Q. Have the new risks facing the electric utilities affected investor confidence in the common stocks of these utilities?

A. Over the past year or so, there has been a significant loss in market value of electric utility stocks. This is shown by the large decline in the utility indexes after reaching a peak in September 1993. For example, the losses in the utility indexes from their peak through month-end October 1994 were:

	Close 10-30-94	Peak	Percent Decline
S&P Public Utilities	153.07	189.49	-19.2%
S&P Electric Utilities	65.62	89.22	-26.5%

While the significant decline in the electric utility index can be traced in part to rising interest rates and a higher cost of capital, the decline can also be attributed to investors' concern about increased business risk. This is shown by the larger decline in the electric utility index as compared to the overall utility index which demonstrates a concern by investor of increasing business risk.

Q. Have the bond rating agencies reacted to the new business risks facing the electric utilities?

A. Yes. Aside from new competitive risks now facing electric utilities, investors today focus upon the risks associated with new environmental regulations, less rapid load growth, changing regulatory risk, large asset concentration, nuclear risk, concerns over electric and magnetic fields ("EMF"), and service territory risk. In response to these risk factors, Standard & Poor's Corporation ("S&P"), a major bond rating agency, has established a risk-adjusted, or matrix, approach to the financial benchmarks used to assess the credit quality of electric utilities (S&P <u>CreditWeek</u>, November 1, 1993). S&P has categorized each electric utility according to its assessment of their business position, e.g., "Above average," "Average," and "Below average." In assigning the electric utilities to a business position, S&P has enumerated the key items of evaluation it considers. They are: Markets and Service Area Economy, Competitive Position, Fuel & Power Supply, Operations, Asset Concentration, Regulation, and Management (S&P <u>Creditweek</u>, July 4, 1994). According to S&P's assessment, the general breakdown of the industry is:

	Number of Electric Companies	Percent
Above average	10	8%
Somewhat above average	11	9
High average	21	17
Average	31	25
Low average	29	23
Somewhat below average	15	12
Below average	7	6
Total	124	100%

S&P has assigned PP&L to the "Average" business position category.

Q. Please describe the background information for PP&L which you considered in connection with your testimony.

A. PP&L is a winter-peaking utility within the PJM power pool which peaks in the summer. The Company derives its revenues from electric sales which are represented by 28% to residential, 23% to commercial, 23% to industrial, 22% to bulk power and interchange, and 4% to other sales customers. The Company's resources include capacity available from coal (46%), nuclear (20%), oil (19%), combustion turbines (6%), non-utility generation (6%), and hydro (3%). These capacity percentages exclude the capacity sold under contract to other utilities. Within the residential sector of the Company's business, approximately 50% of those sales are to customers which use electricity for space heating. These operating characteristics indicate that the Company's risk profile is influenced by competition, the level of general business activity, and the weather. The Company is faced with many of the evolving risk factors which I previously enumerated for the electric utility industry.

Q. What specific factors affect the Company's business risk profile as perceived by investors?

A. The Company's strengths as perceived by investors include:

- An extended period of rate stability
- Strong capacity position
- High levels of generating station availability
- Aggressive marketing and economic development programs
- Marketing of new technologies for efficient use of electricity
- Emphasis on cost control, especially in the area of the size of the workforce
- Initiatives to strengthen its position in the

wholesale markets through marketing of capacity and energy

- Refinancing of $2.7 billion of long-term debt and $739 million of preferred/preference stock over the past 9 years which reduced capital costs by about $133 million annually. The affect of refinancing can be seen in the decline in senior capital cost rates whereby the cost of debt fell from 11.27% to 7.97% and the cost of preferred fell from 9.89% to 7.31% from the prior case to this case.

The factors which adversely affect the Company's business risk profile as perceived by investors include:

- The relatively large concentration of assets in the Susquehanna station
- Deferred Susquehanna costs
- Nuclear decommissioning costs
- Coal mine closure costs, including miners' health care costs
- Relatively high cost of energy obtained from NUGs
- CAAA compliance which will elevated capital and operating costs
- Environmental issues
- Revenue recognition of accrual costs related to post-retirement health care costs

Q. How do the Company's industrial sales and wholesale sales affect its risk profile?

A. The Company's sales profile is strongly influenced by industrial sales and sales to other utilities through interchange and by contract. On a combined basis, the revenues from these sources represent 36% of total Company sales. Industrial sales are usually thought to be of higher risk than sales to other classes of customers. Although no single customer or industry dominates the Company's industrial sales, they are more influenced by the level of business activity and are susceptible to self-generation and/or bypass. The Company's twenty-nine largest industrial customers represent about 7.5% of its revenue. Success in this market is subject to the business cycle, the price of alternative energy sources, and broadening competition which could develop from other utilities or non-utility generators ("NUG") of electricity. To date, the Company has lost only two customers to self-generation. This demonstrates that the Company has been successful in retaining its industrial load through economic development rates, interruptible rates, and aggressive marketing. In the next several years, however, the Company is exposed to the possible loss of about 236.5 million KWH related to sales to a large steel manufacturing customer and of about 173.5 million KWH related to sales to a large paper manufacturing customer.

Further, with the trend toward greater competition in the electric utility industry, the Company will be less secure in the market for bulk energy sales due to the passage of National Energy Policy Act of 1992 ("NEPA"). NEPA removes certain impediments to the construction of NUGs by utility affiliates and independent developers. It also provides the FERC with the authority to order wholesale transmission service (but not retail wheeling). While this act does not provide for direct competition in the retail market for electric energy, additional competition will surely develop in all aspects of the electric utility business. This situation could provide the potential for alternative energy sources for the Company's large volume customers. This situation could also provide the Company with the opportunity for additional off-system sales. It is imperative that the Company maintain competitive pricing in the face of increasing competition and expansion of open access of the transmission network. For PP&L, competitive pricing and maintenance of its market share represent key challenges for the future.

Q. Are there other specific features of the Company's business which must be considered when assessing the Company's risk?

A. Yes. As previously noted, a meaningful portion of the Company's residential customers use electricity for space heating purposes. About-one half of all residential electric sales are to customers which have electrically heated homes. For those residential sales, the Company's revenues are subject to variations caused by weather abnormalities. Also, the Company's residential sales are subject to significant competition from alternative energy sources, especially natural gas and fuel oil in the space heating market. The Company has experienced a decline in the percentage of new residential construction which uses electricity for space heating. From a peak of 69% of new construction which employed electric heat, the Company's share of this market declined to 65% in 1993. The Company's goal is to increase its market share to 68% of new construction.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company is faced with the requirement to invest in new facilities to meet growth and to maintain and enhance the efficiency and reliability of existing facilities. The future capital expenditures are estimated to be:

Year	Capital Expenditures
1995	$ 386,900,000
1996	400,800,000
1997	477,800,000
1998	478,500,000
1999	313,300,000
Total	$2,057,300,000

For PP&L, forecast construction expenditures represent a 22%

($2,057,300,000 ÷ $9,417,064,000) increase in total utility plant (including construction work in progress) from the level at September 30, 1994. Compliance with the CAAA represents a key factor in the Company's future construction program. A summary of potential CAAA expenditures, a portion of which are included in the construction figures listed above, are:

		Operating costs	
	Capital costs	% of '93 Revenues	Amount
Acid Rain			
Phase I	$ 200,000,000	1.5%	$ 40,000,000
Phase II (low est.)	400,000,000	3.0%	75,000,000
Ambient Ozone	230,000,000	1.8%	50,000,000
Hazardous air emissions	310,000,000	1.8%	50,000,000
Total	$1,140,000,000	8.1%	$215,000,000

From a cost perspective, investments in environmental facilities do not add to the Company's revenues other than through rate increases and, indeed, detract from the Company's competitive position. Overall, in the situation where additional capital investment is required, the regulatory process must provide a reasonable opportunity for the Company to actually achieve its cost of capital and attract capital on reasonable terms.

Q. Are there other environmental issues that impact the Company's business risk?

A. Yes. Additional environmental issues facing the Company relate to its fly ash disposal at all but two of its generating stations. Further, additional water treatment facilities will be required at the Company's generating facilities. Other environmental matters relate to the disposal of hazardous and non-hazardous materials to comply with residual waste regulations and to correct groundwater degradation. The Company has also contributed to remediation efforts at several Superfund sites. Finally, concerns over EMF may affect the siting of future transmission facilities by the Company.

Q. How should the Commission respond to the risks facing the Company?

A. The rate setting process should recognize, and take into account, the heightened risk of the electric industry and the specific risk factors facing the Company. As described in the testimony of Mr. Hill, the rate relief requested by the Company in this case represents a necessary prerequisite for the Company to sustain its credit quality. Mr. Hill's testimony also describes the innovative manner in which the Company operates so as to maximize productivity. In response, the Company must be provided a reasonable rate of return which corresponds with the changing risk profile of the electric utility industry.

Fundamental Risk Analysis

Q. Earlier you indicated that a fundamental risk analysis represented the foundation for the determination of the cost of equity. How have you conducted this analysis?

A. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. For this purpose, I have compared PP&L to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and a Barometer Group of electric companies.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index comprised of twenty-four electric power companies, fourteen natural gas companies, and eight telephone companies. These companies are identified on pages 3 and 4 of Schedule 3. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

Q. What criteria have you employed to assemble your Barometer Group?

A. The Barometer Group I have employed in this case includes companies that are engaged in similar business lines, have marketable securities, and have well recognized credit quality. The Barometer Group companies have the following common characteristics: (i) they are contained in the Standard & Poor's Utility Compustat data base; (ii) they have SIC Code 4911 (Electric Service) and 4931 (Electric and other services combined); (iii) they have common stock which is traded on the New York Stock Exchange; (iv) they operate in Pennsylvania or its six contiguous states; (v) they have not cut or omitted their dividends, (vi) they have 1993 operating revenues above $750 million. The companies which comprise the Barometer Group are identified on page 2 of Schedule 2. PP&L shares each of the characteristics of the Barometer Group listed above.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is an important ingredient in analyzing a company's cost of equity because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is directly shown by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus a premium to recognize the higher risk of an equity investment compared to debt.

Q. *How do the bond ratings compare for the Company, the Barometer Group, and the S&P Public Utilities?*

A. Presently, the Company's senior secured debt ratings are A2 from Moody's and A- from S&P. The Company suffered a downgrading of its bond rating from S&P on July 18, 1994. Prior to the downgrading, the Company's outlook was "negative" under the previously higher rating. When the downgrading occurred, S&P noted that the Company's financial condition was insufficient to warrant the formerly higher rating and that prospects for improvement were inadequate. S&P's analysis of the Company's rating is provided on pages 3 and 4 of Schedule 1. Following the downgrading, S&P indicated that the Company's rating outlook is "stable." The Company's credit quality is somewhat weaker than the Barometer Group which has average A2 and A bond ratings from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite bond rating is A2 by Moody's and A by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process.

Q. *What factors influence the bond ratings assigned by the credit rating agencies?*

A. The credit rating agencies consider various qualitative and quantitative factors in assigning grades of creditworthiness. As previously described, S&P has refined its credit analysis through a matrix approach which adjusts its financial benchmarks according to each company's business risk profile. In this regard, S&P has stated:

> "...For a given rating category, expected levels of financial ratios vary with the business or operating risk of a company. A utility with a stronger competitive position, more favorable business prospects, and more predictable cash flows can afford to withstand greater financial risk while maintaining the same credit rating. The revised benchmarks make explicit the linkage between financial ratios and levels of utility business risk as S&P sees it." (S&P Creditweek November 1, 1993)

The new financial benchmarks for an electric utility with an "average" business position include:

Rating	Pre-Tax Interest Coverage	Debt Leverage	Funds from Operations Interest Coverage	Funds from Operations to Total Debt	Net Cash Flow to Capital Expenditures
AA	4.00×	42%	4.50×	32%	110%
A	3.50	47	4.00	25	85
BBB	2.50	54	3.00	19	60
BB	1.75	60	2.00	13	40

For electric utilities with a "below average" business position, more stringent criteria apply, while the financial benchmarks are more lenient for electric utilities with an "above average" business position. As previously noted, S&P has assigned PP&L to the "average" business position category. In comparison, the Barometer Group business position could also be characterized as within the "average" category.

Q. How do the financial data compare for the Company, the Barometer Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedule 1 through Schedule 3. The data cover the five-year period 1989-1993. I will highlight the important categories of relative risk as follows:

Size. In terms of capitalization, PP&L is fairly equal to the average size of the Barometer Group. The S&P Public Utilities are somewhat larger enterprises on average.

Market Ratios. Historical market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher dividend yield for companies which exhibit greater risk as compensation for that risk.[2] Similarly, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings; a high earnings/price ratio is thus indicative of greater risk.

The earnings/price ratios for PP&L and the Barometer Group have been fairly similar and somewhat higher than those of the S&P Public Utilities. The dividend yields were historically somewhat lower for PP&L than for the Barometer Group. As I will subsequently indicate, this situation has changed whereby the dividend yield for PP&L has moved higher than that of the Barometer Group. The dividend yields for the S&P Public Utilities were below both PP&L and the Barometer Group. Historically, the market-to-book ratios were higher for PP&L than for the Barometer Group, but below that of the S&P Public Utilities.

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[2] For example, two otherwise similarly situated firms each paying $1.00 per share in annual dividends would have different market prices at varying levels of risk. That is to say, the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value.

Common Equity Ratio. The level of financial risk is measured by the ratio of long-term debt and other senior capital to permanent capital. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. Today, many public utilities employ less financial leverage than a decade ago in response to heightened business risk. The five-year average common equity ratio, based on permanent capital, was 39.8% for PP&L, 43.6% for the Barometer Group, and 46.3% for the S&P Public Utilities. At year-end 1993, the common equity ratios, based upon permanent capital, were 41.5% for PP&L, 44.2% for the Barometer Group, and 47.3% for the S&P Public Utilities. I should note that the common equity ratios for PP&L and the comparison groups have been computed by including capitalized leases as part of the debt structure of the Company. For rate of return purposes in this case, capitalized leases have been removed from the capital structure because lease payments are recovered elsewhere in the ratesetting process. Historically, PP&L's financial risk has been higher than that of the Barometer Group and the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. During the period 1989-1993, the coefficients of variation were 0.044 (0.6% ÷ 13.6%) for PP&L, 0.103 (1.2% ÷ 11.7%) for the Barometer Group, and 0.103 (1.2% ÷ 11.6%) for the S&P Public Utilities. These comparisons show higher earnings variability for the Barometer Group and the S&P

Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[3] For 1989-1993, the five-year average operating ratios were 68.5% for PP&L, 77.5% for the Barometer Group, and 85.3% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense and preferred stock dividends) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 3.1 times for PP&L, 2.8 times for the Barometer Group, and 2.6 times for the S&P Public Utilities. The Company's aggressive refinancing of high cost debt and preferred stock has assisted in improving coverages in recent years. With the increase in interest rates which has developed since the fall of 1993 (which I will subsequently discuss), fewer opportunities will be available for cost-effective refinancing in the future.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds. The Company has deferred a significant amount of expense for future cost recovery which diminishes its earnings quality --

[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

$255,597,000 of deferred debits, excluding tax items, as of September 30, 1994. Further, the Company expects an increase in the AFUDC percentage in the future as construction costs increase due to the capital costs necessary to comply with the CAAA.

Internally Generated Funds. Historically, the five-year average percentage of internally generated funds ("IGF") to construction expenditures was 133.5% for PP&L, 60.7% for the Barometer Group, and 93.1% for the S&P Public Utilities. In 1993, the Company's IGF represented a much smaller percentage of construction expenditures than in earlier years. PP&L expects IGF to provide only 87% of future construction expenditures during the years 1994-1998.

Betas. The financial data I have been discussing relate primarily to company-specific risks. Market risk for firms with traded stock is measured by beta coefficients, which attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Merrill Lynch publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[4] A comparison

[4] The Merrill Lynch beta coefficient is derived from a straight regression based upon the percentage change in the price of an individual common stock and percentage change in the S&P Composite Index using monthly data over a five-year period. The raw historic beta is adjusted by Merrill Lynch for the measurement effect resulting in underestimates of low beta stocks and overestimates of high beta stocks. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk. Merrill Lynch also provides the coefficient of determination (R^2) which indicates the percent of price fluctuation in the stock which can be attributed to the fluctuation in the S&P Composite Index. Since the coefficients of determination are low

of market risk is shown by the betas provided on page 2 of Schedule 1 (.74 for PP&L), page 2 of Schedule 2 (.68 for the Barometer Group), and page 4 of Schedule 3 (.74 average beta for the S&P Public Utilities and .76 for the S&P Public Utilities Index). Keeping in mind that the electric industry has changed significantly during the past several years, the systematic risk percentage is 100% for PP&L and 92% for the Barometer Group using the S&P Public Utilities' average beta as a benchmark. Alternatively, the systematic risk percentage for PP&L is 97% and the Barometer Group is 89% of the S&P Public Utilities Index.

Q. Please summarize your risk evaluation of PP&L and the Barometer Group.

A. The investment risk of PP&L is, in my opinion, somewhat greater than that of the Barometer Group. This is attributable to the Company's weaker credit quality, as evidenced by the recent downgrading by S&P, its lower equity ratio, and its declining IGF to construction. As such, the Company's equity allowance should appropriately be set toward the upper bound of the range when measured by the results for the Barometer Group.

While my fundamental financial analysis provides the required framework to establish the risk relationships among PP&L, the Barometer Group, and the S&P Public Utilities, the cost rate of common equity must be measured by standard financial models which include the Comparable Earnings approach,

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(i.e., .28 for PP&L, .19 for the Barometer Group and 0.16 as the average for the S&P Public Utilities), it is apparent that the vast majority of the investment risk is unsystematic and hence not explained by the beta.

the DCF model, Risk Premium analysis, and the CAPM. Obviously, differences in risk traits, such as size, business diversification, geographical diversity, regulatory quality, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

Recommended Capital Structure Ratios

Q. Please explain the selection of capital structure ratios for PP&L in this case.

A. In the situation where the operating public utility raises its own long-term debt and preferred stock directly in the capital markets, as is the case for PP&L, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes.

After its corporate reorganization, the Company's previously issued debt and preferred stock will continue to be outstanding. Moreover, PP&L will continue to issue debt and preferred stock directly in the public markets to finance its electric operations. After the reorganization, new common equity will be provided to PP&L from common stock issued by PP&L Resources, Inc. through proceeds from the dividend reinvestment plan and through underwritten public offerings of new common shares. PP&L will also add to its common equity through the retention of a portion of its earnings.

Q. Does Schedule 4 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 4 presents PP&L's capitalization and related capital structure at September 30, 1994, the end of the historic test year. Also shown on Schedule 4 is the PP&L capital structure estimated at September 30, 1995, the end of the future test year. The changes in the Company's capital structure consist of: (i) the actual issuance of $200,000,000 First Mortgage Bonds on October 1, 1994, (ii) the planned redemption of $95,500,000 of 9 1/4% First Mortgage Bonds during the period June through August 1995, (iii) the planned redemption of $55,000,000 of 9 3/4% Series Pollution Control Bonds in June or July 1995, (iv) the planned issuance of $55,000,000 of replacement pollution control bonds, (v) proceeds of $100,000,000 from new common equity in August 1995, (vi) about $7,000,000 from the Employee Stock Ownership Plan, (vii) about $78,000,000 from the Dividend Reinvestment Plan, and (viii) the Company's projection of retained earnings at September 30, 1995. The redemptions described above will be dependent upon future capital market conditions. I have also adjusted the Company's capital structure to recognize the ratesetting treatment of the call premium on the early redemption of high cost long-term debt and preferred and preference stock which was redeemed.

Q. Please describe these adjustments.

A. I have adjusted the principal amounts of long-term debt and preferred stock to exclude the amounts used to finance premiums on the early redemption of high coupon debt and high dividend preferred and preference stock. To do otherwise would deny PP&L the full return on the premiums paid to redeem this high cost capital since additional amounts of capital were issued to pay the call premiums. The amounts issued to finance the call premiums do not increase the Company's rate base. That is to say, no additional rate base was created through additional debt and preferred stock necessary to finance this transaction, and therefore a special adjustment is required to provide the return necessary to service this additional capital. Hence, PP&L's long-term debt and preferred stock amounts must be adjusted for this disparity in order that the return necessary to service the capitalization is produced from rate base investment times the overall rate of return.

This adjustment is equitable since customers receive the cost savings resulting from these refinancing in the form of a lower overall rate of return, and PP&L recovers all costs incurred in providing these benefits to the customers. To accomplish these savings, the Company paid the debt and preferred and preference holders a premium for surrendering their securities prior to maturity. These premiums represented an investment made by PP&L to reduce its overall cost of capital. Since the reduced interest costs and preferred stock dividends are reflected in the lower cost of capital to ratepayers, it is appropriate that the Company recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium as a part of the embedded cost rates of capital.

Q. Are there additional adjustments necessary to reflect the call of high cost preferred and preference stock?

A. Yes. Unlike the situation where the Company recorded the call premiums on the long-term debt as deferred debits for future recovery in rates, no similar accounting was available to the Company for the call premiums associated with the early redemption of the preferred and preference stock. Instead, those amounts were charged directly to retained earnings. Also, the Company financed the call premium with the additional sale of preferred stock. The Commission has encouraged utilities to refinance high-cost capital and has stated that a utility will not be penalized for undertaking a refinancing. Hence, it is necessary to restore the Company's capital structure to the condition which existed prior to the refinancing of the high cost preferred and preference stock. To accomplish this, it is necessary to reduce the preferred stock outstanding by the amount of the call premium and to remove a similar amount for the charge to retained earnings for the call premiums. These adjustments maintain the aggregate amount of total capitalization for the Company. All of my adjustments to the Company's capital structure for call premiums comply with adjustments routinely approved by the Commission for other utilities, such as PECO Energy and National Fuel Gas Distribution Corporation.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratemaking is prospective, the rate of return should reflect known conditions which will exist during the period of time the proposed rates are to be effective. I will adopt the Company's forecast capital structure ratios at September 30, 1995 of 46.53% long-term debt, 7.59% preferred stock, and 45.88% common equity. I have excluded short-term debt from my capital structure because the Company's AFUDC rate reflects the interest cost of the short-term debt. The non-permanent nature of the short-term borrowings which are incurred on an interim basis to finance construction expenditures, indicates that short-term debt will ultimately be refinanced with permanent capital in the desired proportions of long-term debt, preferred stock, and common equity. Further, in previous cases, the Commission has not employed short-term debt as part of the capital structure for the Company or other electric utilities.

Embedded Senior Capital Cost Rates

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of PP&L must be used for the purpose of developing a fair rate of return. It is essential that the cost rates of long-term debt and preferred stock are related to the same proportion of senior capital employed to arrive at the capital structure ratios. This procedure is consistent with prior ratesetting procedures used by the Commission in prior orders for PP&L. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 5, I have computed the actual embedded cost rate of long-term debt at September 30, 1994. On page 2 of Schedule 5, I have shown the estimated embedded cost rate of long-term debt at September 30, 1995. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 3 of Schedule 5. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 7.97% forecast embedded long-term debt cost rate at September 30, 1995 as shown on page 2 of Schedule 5. This rate is related to the amount of long-term debt shown on Schedule 4 which provides the basis for the 46.53% long-term debt ratio. I have recognized the costs associated with the Company's early redemption, through the call, of high cost debt. As previously explain, it is necessary to compensate PP&L for the costs incurred to lower the embedded debt cost rate which reduces the cost of capital charged to ratepayers. I have also recognized as part of the long-term debt cost rate the reduction in the Company's embedded debt cost rate for the gains on previously reacquired debt. This has been accomplished by recognizing the amortization of actual gains over the remaining life of each issue. As the Company has not deferred this gain on its books and since no investment was required to realize this gain, the principal amount of debt has not been adjusted in this regard. This procedure conforms with the method previously accepted by the Commission.

The 7.97% embedded long-term debt cost rate reflects the Company's future test year debt financing plans which include the issuance of one series of pollution control debt. When this issue has been placed, the future test year debt cost rate will be updated.

Q. What preferred stock cost rate have you calculated for the Company?

A. For the future test year, I have calculated a 7.31% embedded cost of preferred stock as shown on page 2 of Schedule 6. I have included in the embedded cost rate of preferred stock the unrecovered issuance costs and the call premium on the redemption of the high cost preferred and preference stock. The unrecovered issuance expenses and the call premium has been amortized over the original remaining term of the issue. This procedure was adopted because of the difficulty of assigning those costs to a specific replacement issue. These adjustments correspond to those which I previously discussed concerning the Company's capital structure ratios. I will adopt the 7.31% embedded cost rate of preferred stock which is related to the 7.59% preferred stock ratio shown on Schedule 4. The details regarding the individual cost rates for each series of preferred stock are provided on page 3 of Schedule 6.

Cost of Equity--General Approach

Q. Previously, you indicated that a firm's investment risk influences the required rate of return. How have you considered these factors in your recommended rate of return on common equity?

A. Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment.

Q. Which methods have you used to measure the cost of equity?

A. I have applied a variety of well-accepted financial models to measure the cost of equity. In this regard, I have relied upon the Comparable Earnings approach, the DCF model, the Risk Premium approach, and the CAPM. In general, the use of more than one approach provides a superior foundation to arrive at the cost of equity.

The Comparable Earnings approach has been used extensively in rate of return analysis for over a half century. Its popularity diminished in the 1970s and 1980s with the advent of other market based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that utilities can compete effectively in the capital markets. The Comparable Earnings approach directly considers those requirements and, in addition, has considerable intuitive appeal because it fits the established standards for a fair rate of return set forth in the Bluefield and Hope decisions. The Hope decision requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

The traditional DCF model is useful and can provide some insight into the cost of equity, but it is not an approach which should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. In a June 6, 1991 article in The Wall Street Journal, "Heard on the Street," a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. This study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables which explain stock price growth. This study confirms that a combination of methods should be used to measure the cost of equity.

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

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

It is important to reiterate that no one of these methods can be applied in an isolated manner to analyze the cost of equity. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity.

Comparable Earnings Approach

Q. You indicated that the Comparable Earnings approach has a very long history in the determination of a fair rate of return. How have you applied this approach in this case?

A. The details of my Comparable Earnings approach and the evidence in support of my conclusion are set forth in Appendix B. There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the utility, and then use the results for all companies within that industry as a benchmark. The second approach requires the selection of parameters which represent similar risk traits for the utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. I have followed the latter approach with the further qualification that the comparable risk companies exclude public utilities. As such, my Comparable Earnings approach avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other utilities. Rather, it provides an indication of an earnings rate derived from non-regulated companies which are subject to competition in the marketplace and not rate regulation. Since, as previously noted, regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a utility can provide insight into a fair rate of return.

Q. How have you implemented the Comparable Earnings approach in this case?

A. To implement the Comparable Earnings approach, I have used both historical realized returns and forecast returns for non-utility companies. The results of the Comparable Earnings method can be applied directly to an original cost rate base because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when prices and book values diverge significantly.

As a starting point, I employed the Value Screen Data Base which consists of approximately 1,600 companies. Excluded in the selection process were companies with a foreign exchange listing and master limited partnerships (MLPs). The statistics for the companies selected for the Comparable Earnings approach are provided on page 1 of Schedule 7. In selecting these companies, I employed six criteria to establish comparability with PP&L and the Barometer Group. These screening criteria included a range of Timeliness Rank of 3, 4 and 5 (PP&L's Timeliness Rank is 4 and the Barometer Group's average Timeliness Rank is 4.0), Safety Ranking of 1, 2 and 3 (PP&L's Safety Rank is 2.0 and the Barometer Group's average Safety Ranking is 1.9), Financial Strength of B+, B++, A and A+ (PP&L's Financial Strength is B++ and the Barometer Group's average Financial Strength is A), Price Stability of 80 and higher (PP&L's Price Stability is 95 and the Barometer Group's average Price Stability is 99.0), Value Line betas between .55 and .75 (PP&L's Value Line beta is .65 and the Barometer Group's average Value Line beta is .68), and Technical Rank of 3 and 4 (PP&L's Technical Rank is 3 and the Barometer Group's average Technical Rank is 4.0). In this case, twenty-three (23) non-regulated firms fit the criteria and comprise the group I have employed for the Comparable Earnings approach.

Q. What are the results of your Comparable Earnings analysis?

A. The historical average rate of return on book common equity was 12.6%, as shown on page 2 of Schedule 7. The forecast rate of return as published by Value Line is shown by the 14.4% average as indicated on page 2 of Schedule 7. There is some downward bias in these figures because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks.

The data shown on Schedule 7 page 2 indicate that higher forecast returns are expected in the future based upon increased business activity which followed the recessionary period of 1990-1991 which influenced the historical returns. It is useful to consider a relative long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. The average of the historical and forecast rates of return is 13.50% (12.6% + 14.4% = 27.0% ÷ 2).

Q. Have you sought to verify the reasonableness of your Comparable Earnings approach by considering the market derived cost of equity for your non-regulated company group?

A. Yes. These data are contained on page 3 of Schedule 7. On that schedule, I have computed a DCF cost of equity for each of the 23 non-regulated firms which comprise my Comparable Earnings Group. The result is 15.0% which exceeds slightly the projected 3-5 year returns for the non-regulated companies and shows that the returns calculated from the book values for these companies provides a reasonable basis to determine a fair rate of return.

<u>Discounted Cash Flow Analysis</u>

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix C. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The cost of equity based on a combination of these two components represents the total return which investors can expect with regard to an equity investment.

Among other limitations of the model, there is a certain element of circularity in the DCF when applied in public utility rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations which include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix C, the DCF approach has other limitations which diminish its usefulness when stock prices significantly diverge from book values in the ratesetting context. When stock prices diverge from book values by a significant margin, the DCF method will lead to a misspecified cost of equity. If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to a net original cost (book value) rate base, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor required cost of equity. The monthly dividend yields for PP&L and the Barometer Group for the twelve months ending October 1994 are shown graphically on pages

1 and 2 of Schedule 8, respectively. The monthly dividend yields shown on Schedule 8 reflect an adjustment to the month end prices to reflect the build up of the dividend in the price which has occurred since the last ex-dividend date dividend (i.e., the date 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). An explanation of this adjustment is provided in Appendix C. For the twelve months ending October 1994, the average dividend yield was 7.48% for PP&L and 7.28% for the Barometer Group based upon a calculation using annualized dividend payments and adjusted month end stock prices. The dividend yields for the more recent six and three month periods were 8.26% and 8.37% for PP&L, respectively, and 7.80% and 7.80% for the Barometer Group, respectively. The graphs presented on Schedule 8 indicate an increasing trend in the cost of equity since the fourth quarter of 1993.

I typically employ a twelve month dividend yield for the purpose of a DCF calculation. However, by the time this case is decided, data from late 1993 will clearly be stale. As a consequence, I have used, for the purpose of my direct testimony, a representative dividend yield of 8.25% for PP&L and 7.75% for the Barometer Group. I have proposed this approach in this case to avoid overly stale data and to recognize the upward trend in capital cost rates which have developed since October 1993. While not linked to a specific historical monthly average, the dividend yields I have used for PP&L and the Barometer Group are above the twelve month average and near the six month and three month average. The use of these representative dividend yields will be more reflective of current capital cost rates while avoiding spot yields and recognizing that the longer term averages do not fully reflect current market sentiment. As this case progresses, I intend to provide additional dividend yield data so that the Commission has the benefit of the most recent twelve-month average by the close of the record.

For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model which must reflect investor anticipated future cash flows. For PP&L, I have adjusted the 8.25% dividend yield in three different but generally acceptable manners, and used the average of the three of 8.49% as calculated in Appendix C. Similarly, Appendix C provides the basis for the 7.97% adjusted dividend yield which I have calculated for the Barometer Group.

Q. What measures of growth influence investor judgment regarding the cost of equity?

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

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Historical performance and analysts' forecasts support my opinion of the growth expected by investors. While some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their current dividend yield requirements. Some regulatory agencies have also acknowledged that a blended approach which recognizes the preceding factors is required in the selection of the DCF growth rate. I have followed an approach that is not rigidly formatted, because investors do not behave in such a manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques should be evaluated when formulating a judgment of investor expected growth.

As explained in Appendix C, historical performance and published forecasts support my opinion that a prospective growth rate of 3.50% is reasonable for PP&L and for the Barometer Group based upon company-specific variables. While the DCF growth rate cannot be established solely with a mathematical formulation, the growth rates for the PP&L and Barometer Group are within the array of growth rates shown by the company-specific accounting values (earnings per share, dividends per share, book value per share, retention growth, and cash flow per share). However, as previously noted, market-wide factors also influence the capital gains yield expected by investors. In my opinion, the DCF growth rate must represent the capital gains expectations of investors given the growth prospects for the economy and the new business environment of electric utility industry. Moreover, the DCF growth rate must be representative of the relative proportion that the capital gains yield provides within investors' total return expectations.

Therefore, for the purpose of this case I have added a modest 0.5% growth rate for market-wide factors to the growth rate shown by company-specific variables. As previously indicated, there are a wide variety of factors that influence investor expected returns which are not linked specifically to company-specific near-term performance. Those factors would include overall business conditions, monetary policy, fiscal and tax policy, all of which I would categorize as qualitative influences on investors' total return expectations. In addition, as the electric utility industry adjusts to the new business environment, additional opportunities will surely develop beyond the five-year horizon typically considered by the analysts' forecasts. The combination of both quantitative factors, as shown by company-specific variables, and qualitative factors, as shown by general investor sentiment, together form the foundation for the capital appreciation (i.e., capital gains yield) that investors expect from owning a common stock. By considering both company-specific and market-wide factors, it is my opinion that a 4.00% growth rate is warranted for PP&L and the Barometer Group. This growth rate is comprised of 3.50% growth related to company-specific variables and 0.5% growth for market-wide factors. It is my opinion that to make the DCF model at all useful, the growth rate component combined with the dividend yield must provide a result that conforms with the mix of current return from dividends and long-term returns from capital gains. With the significant declines in the market prices for utilities which I previously noted, there exists the potential for a rebound in electric utility stock prices which could add to the capital gains yield to be realized by investors. Moreover, it must be recognized that at a minimum, the long-run growth rate must be higher than anticipated future inflation for investors to experience real appreciation in future dividend receipts and in the value of the stock. Therefore, it is necessary that the DCF growth rate reflect both the long-run real growth potential in the dividend and stock value, in order to make the DCF results a viable contributor to the rate of return determination process.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield and growth.

A. For reasons previously explained, I have utilized a representative dividend yield adjusted in a forward-looking manner for my DCF calculation. These dividend yields are used in conjunction with the growth rates previously developed. The

DCF return (i.e., "k") is the sum of the adjusted dividend yield (i.e., "D_1/P_0") and the growth rate (i.e., "g"). The resulting DCF cost rates are:

	D_1/P_0	+	g	=	k
PP&L	8.49%	+	4.00%	=	12.49%
Barometer Group	7.97%	+	4.00%	=	11.97%

These DCF results represent the simplified form of the model which contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate shown above provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market since price-earnings multiples do not remain constant. Moreover, the DCF results do not reflect a modification factor to recognize that prices of stock exceed the book value of equity. For example, PP&L through its newly formed holding company will issue new common stock and will incur issuance costs in the future test year. As such, the DCF results shown above would be inadequate to satisfy the test of reasonableness because they fail to account for the cost to issue new common equity. In the situation where the regulatory model fails to recognize all of a utility's costs, regulatory disallowances which ignore flotation costs elevate a utility's risk profile.

<u>Risk Premium Analysis</u>

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix D. I will summarize them here. The cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 9.00% yield represents a reasonable estimate of a prospective long-term debt cost rate for a public utility with an A bond rating. As I will subsequently discuss, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 11. For the twelve months ending October 1994, the yield on Moody's A rated monthly index of public utility bonds trended upward by 1.83%, i.e., from 7.03% in October 1993 to 8.86% in October 1994. The average yield over the period was 8.04%.

Forecast yields on A rated public utility long-term debt (according to the December 1, 1994 Blue Chip Financial Forecast) are as follows:

Quarter	Yield
4th Qtr. 1994	9.0%
1st Qtr. 1995	9.2
2nd Qtr. 1995	9.2
3rd Qtr. 1995	9.1
4th Qtr. 1995	9.1

The average analysts' projection for the fourth quarter of 1995 is bounded by an 9.9% average of the highest ten estimates and a 8.4% average of the lowest ten estimates. Given these forecasts and the recent rise in long-term interest rates, a 9.00% yield on A rated public utility bonds represents a reasonable expectation.

Q. What public utility equity risk premium have you determined from your studies?

A. Appendix D provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities, from which I derived the equity risk premium for the PP&L and Barometer Group. To develop an appropriate risk premium I have analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. As shown by the values indicated on page 2 of Schedule 12, the indicated risk premiums for the various time periods analyzed are 5.25% (1928-1993), 6.24% (1952-1993), 5.39% (1974-1993), and 5.73% (1979-1993).

The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium which conforms more nearly with present investment fundamentals and removes some of the more distant data from the analysis. Using the summary values provided on page 2 of Schedule 12, the 1928-1993 period provides the lowest indicated risk premium, while the 1952-1993 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.56% (5.39% + 5.73% = 11.12% ÷ 2) is shown from data covering the periods 1974-1993 and 1979-1993 which represents the more recent results.

I previously enumerated various differences in fundamentals among PP&L, the Barometer Group, and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 4.75% represents a reasonable common equity risk premium in this case. This represents 85% (4.75% ÷ 5.56%) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Barometer Group compared with that of the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the prospective attraction rate of long-term public utility debt?

A. The cost rate of common equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The rate of return on common equity is:

$$i + RP = k$$
$$9.00\% + 4.75\% = 13.75\%$$

Capital Asset Pricing Model

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM also contains a variety of assumptions, as I discuss in Appendix E. Therefore, this method should be used with other methods to measure the cost of equity as each will complement the other and will provide a result which will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM contains a yield on a risk-free interest bearing obligation plus a return representing a premium which is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix E. To compute the cost of equity with the CAPM, three components are necessary, i.e., a risk-free rate of return ("**Rf**"), the beta measure of systematic risk ("β"), and the market risk premium ("**Rm - Rf**") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, it is necessary to employ firms with traded stocks in order to calculate the CAPM. In this regard, I have performed a CAPM calculation for PP&L and the Barometer Group. In contrast, my Risk Premium approach also considers industry and company specific factors. As a consequence, my Risk Premium approach is more comprehensive than the CAPM as it reflects industry and company specific risk characteristics in the cost of equity.

Q. What forms of the CAPM have you used in this case?

A. I have employed both the traditional and zero-beta forms of the CAPM. While similar in their underpinnings, the zero-beta CAPM is intended to account for the return on a portfolio that has no covariability with the market portfolio. That is to say, a portfolio with a zero-beta would have no volatility relative to the market. In this case, I have not attempted to identify such a portfolio. Rather, I have redefined certain terms within the traditional CAPM. Specifically, I have set the risk-free rate at the yield on intermediate Treasury obligations in the zero-beta CAPM. I have further segmented the market premium into two parts. One-half of the market premium is combined with the risk-free rate to represent the return on a zero-beta portfolio. The remaining one-half of the market premium is adjusted for the systematic (i.e., beta) risk of PP&L and the Barometer Group.

Q. What betas have you used in the CAPM?

A. For my CAPM analysis, I have used an average of the Merrill Lynch and Value Line betas. As shown on page 1 of Schedule 13, the Merrill Lynch adjusted beta is .74 for PP&L and .68 for the Barometer Group, while the Value Line beta is .65 for PP&L and .68 for the Barometer Group. The average beta is .70 for PP&L and .68 for the Barometer Group, as shown on page 1 of Schedule 13. These average betas have been used in both the traditional and zero-beta forms of the CAPM.

Q. What risk-free rate have you used in the traditional CAPM?

A. For reasons explained in Appendix E, the yield on long-term (i.e., 30-year) Treasury bonds represents the correct measure of the risk-free rate of return in the traditional CAPM. In this regard, I have considered the yields on 30-year Treasury Bonds using both historical and forecast data. As shown on page 2 of Schedule 13, the historical yields on 30-year Treasury bonds have trended upward during the past twelve months ended October 1994. While the twelve month average yield was 7.08%, the yield on 30-year Treasury bonds increased by 2.00% during the past twelve months, i.e., from 5.94% in October 1993 to 7.94% in October 1994. As shown on page 4 of Schedule 13, forecasts published by Blue Chip on December 1, 1994 indicate that the yields on 30-year Treasury Bonds will be in the range of 8.1% to 8.2% during the next five quarters. From both the historical and forecast data, a risk-free rate of return of 8.00% for Treasury bonds is reasonable for CAPM purposes.

Q. What market premium have you used in the traditional CAPM?

A. As developed in Appendix E, my calculation of the market premium is developed from both historical market performance and by the Value Line forecasts. The resulting market premium is 7.85% which represents the average market premium using the Value Line forecasts and the historical SBBI data. This market premium and the risk-free rate of return developed above imply a 15.85% (8.00% + 7.85%) total return for the market of equities. A total market return of 15.85% represents a reasonable investor expectation given the historical average returns of 14.94% and 14.50% for the past ten and five years, respectively, and the Value Line forecasts which indicate total returns of 16.79% for the future. As such, the range of historical and forecast returns shows that the total market return implied by the CAPM analysis is reasonable.

Q. What CAPM result have you determined for PP&L and the Barometer Group using the traditional CAPM?

A. Using the 8.00% risk-free rate of return, the average beta of .70 for PP&L and .68 for the Barometer Group and the appropriate market premiums, the following CAPM results are indicated:

	Rf + b (Rm-Rf) = k
PP&L Corp.	8.00% + .70 (7.85%) = 13.50%
Barometer Group	8.00% + .68 (7.85%) = 13.34%

Q. What risk-free rate have you used in the zero-beta form of the

CAPM?

A. For the zero-beta form of the model, I have used the yield on shorter term intermediate (i.e., 10-year) Treasury notes. In this regard, I have considered the yields on 10-year Treasury Notes using both historical and forecast data. The historical average yield on 10-year Treasury Notes was 6.72% for the twelve months ended October 1994. As shown on page 2 of Schedule 13, the yield on 10-year Treasury notes has risen from 5.33% in October 1993 to 7.74% in October 1994, or an increase of 2.41%. This indicates that the yield on shorter term Treasury obligations has increased further than the yield on longer term Treasuries. This situation indicates that the yield curve has flattened over the past twelve months. For 10-year Treasury Notes, the Blue Chip forecast indicates that the prospective yields are within the range of 7.9% to 8.1% during the next five quarters. Due to the change in the slope of the yield curve during the past twelve months, a 10 basis points gap is now representative of the yield difference between intermediate term and long-term Treasury yields. From both the historical and forecast data, a risk-free rate of return of 7.90% for Treasury Notes is reasonable for the zero-beta form of the CAPM.

Q. What market premium have you developed for the zero-beta form of the CAPM?

A. To develop a return on a portfolio with a zero-beta ("Rz"), I have added one-half of the market premium to the intermediate term Treasury note yield. Here, the Rz is 11.85% (7.90% + 3.95%). The market premium which provides the basis for the return on the zero-beta portfolio was calculated in a manner similar to that described in Appendix E for the traditional

CAPM. Here, the forecast market premium was 8.89% (16.79% - 7.90% = 8.89%) and was combined with the historical results taken from the SBBI data series (i.e., 12.3% - 5.4% = 6.9%) to produce an average 7.90% (8.89% + 6.9% = 15.79% ÷ 2) market premium. One-half of the market premium (7.90% ÷ 2 = 3.95%) was then assigned to the zero-beta portfolio and the remaining 3.95% was adjusted for the systematic risk of PP&L and the Barometer Group.

Q. What CAPM result have you determined for PP&L and the Barometer Group using the zero-beta form of the CAPM?

A. Using the 11.85% return on a zero-beta portfolio, the average beta of .70 for PP&L and .68 for the Barometer Group and the appropriate market premium, the following results are indicated:

	Rz	+	b	(Rm-Rz)	=	k
PP&L	11.85%	+	.70	(3.95%)	=	14.62%
Barometer Group	11.85%	+	.68	(3.95%)	=	14.54%

Q. What rate of return is indicated from the traditional and zero-beta form of the CAPM?

A. The average CAPM results are 14.06% (13.50% + 14.62% = 28.12% ÷ 2) for PP&L and 13.94% (13.34% + 14.54% = 27.88% ÷ 2) for the Barometer Group. As previously explained, I have supplemented the results of the traditional CAPM with a zero-beta CAPM. As explained in Appendix E, the zero-beta CAPM recognizes that the traditional CAPM may understate the cost of common equity for companies with a beta below 1.0, such as public utilities. Therefore, in order to avoid this understatement of the cost of equity when the beta is less than 1.0, I have utilized the zero-beta CAPM along with the traditional CAPM.

Appropriate Rate of Return on Equity

Q. You stated earlier that an equity return of 13.00% would be appropriate. What is the basis of your recommendation?

A. My recommendation is derived from the results of the Comparable Earnings analyses, DCF model, the Risk Premium approach, and the CAPM. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Comparable Earnings	DCF	Risk Premium	CAPM	Average
PP&L	13.50%	12.49%	13.75%	14.06%	13.45%
Barometer Group	13.50%	11.97%	13.75%	13.94%	13.29%

From the array of cost rates shown in the summary table provided above, all measures of the cost of equity are above 13.00% except the results of the DCF approach. For the Barometer Group, three of the measures show a cost of equity of between 13.50% and 13.94%. For PP&L, those same three measures indicate a range of 13.50% to 14.06%. The DCF results standing alone indicate a cost of equity of approximately 12.5% using PP&L stock market prices and approximately 12.0% using the average Barometer Group stock market prices.

It is my opinion that a 13.00% cost of equity is indicated at this time due to the new risks facing the electric utilities after the passage of the NEPA. As I indicated earlier in my fundamental risk analysis, the Company's financial risk has been above that of the Barometer Group. Moreover, it is my opinion that a 13.00% cost of equity is necessary to support reasonable credit quality in light of the new credit quality benchmarks established by S&P for the electric utilities. As a consequence, the Company must be provided an opportunity to experience a financial profile that fits those criteria and is commensurate with the new business risks for electric utilities.

It is my understanding that the Company has adopted my 13.00% rate of return on common equity in computing its cost of service for the future test period. In my opinion, this rate of return is reasonable, keeping in mind that the cost of capital utilized by the Commission to set the Company's rates merely represents an opportunity for the Company to achieve a particular level of earnings.

Overall Fair Rate of Return

Q. What overall fair rate of return has the Company requested in this case?

A. The Company has requested an opportunity to earn a 10.22% overall fair rate of return applicable to its original cost rate base in the future test period. This rate of return is shown on Schedule 14, along with the capital structure ratios and embedded cost rates which I previously developed.

Q. How have you sought to test the reasonableness of the Company's overall rate of return request?

A. Yes. Coverage is a test which reveals the level of protection that the utility can supply for its fixed obligations. Interest coverage is measured on both a before- and after-income tax basis. Normally, before-income tax coverage is used for the purpose of a company's debt interest coverage and overall after-income tax coverage is the measure employed with regard to interest charges and preferred stock dividends.

It is important to re-emphasize that public utilities must compete in the capital markets to attract needed future dollars and, as such, interest coverage should be used as a test to measure the adequacy of the return rate opportunity provided. Of course, it is not the only factor to be considered in testing the appropriate rate of return and must be viewed in relation to an individual company's degree of financial leverage and cash flow benchmarks. Maintenance of a strong A bond rating financial profile is the appropriate regulatory objective and an AA bond rating should be encouraged. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions.

Q. What credit quality measures are reflected in the Company's rate of return request?

A. Using a 42.1435% statutory federal and state income tax rate, the pre-tax coverage of interest expense would be 4.03 times assuming the Company actually realized the 10.22% overall rate of return shown on Schedule 14. Post-tax coverage of interest expense would be 2.75 times and overall coverage of interest and preferred stock dividends would be 2.40 times after taxes.

The pre-tax interest coverage and debt leverage shown on Schedule 14 should be viewed in the context of the new S&P bond rating criteria which present levels expected to be achieved, rather than the opportunity provided by my recommendation. With the new credit quality benchmarks, the Company needs to achieve the credit quality profile reflected in my rate of return recommendation. The Commission should encourage higher levels of interest coverage in the context of higher credit quality standards for the electric utilities and the need to attract capital to finance the Company's future construction requirements.

In conclusion, the Company should be allowed to implement rates based on a 10.22% overall rate of return so that it can compete in the capital markets and be adequately compensated for its changing business risk.

Q. Does this conclude your prepared direct testimony?

A. Yes.

PENNSYLVANIA POWER & LIGHT COMPANY

Appendices A Through E to Accompany

the Direct Testimony

of

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

Concerning

Fair Rate of Return

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

In 1994, I formed P. Moul & Associates, an independent utility consulting firm. In my capacity as Managing Consultant and for the past twenty years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before twenty-six (26) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Virginia, and West Virginia; and the Philadelphia Gas Commission. The subject of this testimony concerns principally fair rate of return and financial matters. In addition, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

The following tabulation provides a listing of the electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility cases in which I have been involved as a witness:

Ansonia Derby Water Company, The	Docket No. 810805, 830306, 89-05-02
Appalachian Power Company	
Retail Operations	Case #PUE920081
Wholesale Operations	Docket No. ER92-323/92-324
Artesian Water Company	P.S.C. Docket No. 935, 80-22, 82-20, 87-3
Atlantic City Electric Co.	ER 9009-1090J
Bay State Gas Company	D.P.U. Case No. 1122, 1535, 89-81, 92-111

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Berkshire Gas Company, The	D.P.U. Case No. 905, 1490, 86-82, 89-112, 90-121, 92-210
Blue Mountain Consolidated Water Company	Docket No. R-78100686
Borough of Butler-Electric Department	Docket No. 792-84, 8503-303
Borough of Media-Water Utility	Docket No. R-891289
Boston Gas Company	D.P.U. Case No. 87-161, 90-55, 93-60
Bridgeport Hydraulic Co.	DPUC-90-05-04, 93-01-02
Browning-Ferris Industries of Elizabeth, N.J., Inc.	Docket No. SR8506-643
Browning-Ferris Industries of Paterson, N.J., Inc.	Docket No. 8410-1090, SR 86121416
Browning-Ferris Industries of South Jersey, Inc.	Docket No. SR8509-940
Cambridge Electric Light Co.	
Retail Operations	DPU Docket No. 89-109, 92-250
Wholesale Operations	Docket No. ER90-283-000
Canal Electric Company	Docket No. ER84-74-000, ER88-505-000, ER89-66-000, ER90-245-000
CNG Transmission Corp.	Docket No. RP94-96-000
Coastal Utilities, Inc.	Docket No. 3792-U
Columbia Gas of Maryland	Docket No. 93-8567
Columbia Gas of New York, Inc.	Case No.88-G-181, 89-G-1057
Columbia Gas of Ohio, Inc.	Case No. 88-718-GA-AIR, 89-616-GA-AIR
Columbia Gas of Pennsylvania, Inc.	Docket No. R-832493, R-870832, R891468, R-901873, R-943001
Columbia Gas Transmission Corp./Columbia Gulf Transmission Company	Docket No. RP 86-167-000/ TC 86-21-000/RP 86-168-000, RP 89-249-000/RP 89-250-000, RP 90-107-000/RP 90-108-000, RP 91-160-000/RP 91-161-000
Columbia Gulf Transmission Company	Docket No. RP94-219-000
Commonwealth Electric Company	DPU Case No. 88-135/88-151, DPU-90-331
Commonwealth Gas Company	DPU Case No. 87-122, 91-60
Commonwealth Gas Services, Inc.	Case No. PUE900034, Case No. PUE920037
Connecticut-American Water Company	Docket No. 86-12-08, 90-07-17, 92-06-12
Conowingo Power Company	Case No. 7589, 7982, Case No. 8352
Consumers Power Company	ER92-331/332-000
Continental Telephone Co. of Illinois	Docket No. 81-0114, 83-0071

Continental Telephone Co. of Kentucky	Case No. 8182
Continental Telephone Co. of Maine	Docket No. 83-61
Continental Telephone Co. of Michigan	Case No. U-6677
Continental Telephone Co. of Missouri	Case No. TR-82-223
Continental Telephone Co. of New York, Inc.	Case No. 28379
Continental Telephone Co. of North Carolina	Docket No. P-128,Sub. 3
Continental Telephone Co. of Pennsylvania	Docket No. R-822276
Continental Telephone Co. of the South	
Alabama Operations	Docket No. 17968
Florida Operations	Docket No. 820054-TP
Continental Telephone Co. of South Carolina	Docket No. 80-225-C
Corning Natural Gas Corp.	Case No. 29530, Case No. 88-G-001, Case No. 88-G-062
Delaware Public Service Commission	
Chesapeake Utilities Corporation	P.S.C. Docket No. 867
Sussex Shores Water Company	P.S.C. Docket No. 805, 883
Tidewater Utilities, Inc.	P.S.C. Docket No. 22-79
Duquesne Light Company	Docket No. R-80011069
Edgeboro Disposal, Inc.	Docket No. 849-996
Fall River Gas Company	D.P.U. Case No. 1557, 91-61
General Telephone Company of Pennsylvania	Docket No. R-850229
Granite State Gas Transmission, Inc.	Docket No. RP86-99-000, RP91-164-000
Great Valley Water Company	R.I.D. 342
Hackensack Water Company	B.P.U. Docket No. 847-698, WR8506-663, WR90080792J
Honesdale Gas Company	Docket No. R-78070643
Indiana Gas Company, Inc.	Cause No. 38080, 39353
Indian Rock Water Company	A. 99560
Kentucky-American Water Co.	Case No. 91-361
Keystone Water Company	Docket No. R-842755, R-850245
Lockhart Power Company	
Retail Operations	Docket No. 89-178-E, 90-480-E, 91-671-E
Wholesale Operations	Docket No. ER84-199-000
Long Island Water Company	Case No. 93-W-0455
Mebane Home Telephone Company, Inc.	Docket No. P35, Sub. 71
Middlesex Water Company	Docket No. 783-254, 804-266, 815-467

Midwest Gas	
Iowa Operations	IUB RPU-90-6
Minnesota Operations	Docket-G-010/GR90-678
Monmouth Consolidated Water Company	Docket No. WR 8708-0856
National Fuel Gas Dist. Corp.	
New York Division	Case No. 27776, 27934, 28158
Pennsylvania Division	Docket No. R-79090956, R-811600, R-822145, R-942991
New Jersey-American Water Co.	Docket No. WR88070839, WR89080702J, WR90090950J, WR91081399J, WR92090908J WR94030059
New Jersey Water Company	Docket No. 834-292, WR8706-492
New York-American Water Co.	Case No. 89-W-180, Case No. 92-W0494
Newco Waste Systems of New Jersey, Inc.	Docket No. SR8509-907, SR88091091
North East Water, Inc.	
North Penn Gas Company	
Retail Operations	Docket No. R-80111375, R-822261, R860535, R-922276
Wholesale Operations	Docket No. RP82-132-000, RP85-193-000, RP89-237-000
Northern Utilities, Inc.	
Maine Division	Docket No. 82-15, 83-218
New Hampshire Division	Docket No. DR83-90, DR88-029 DR91-081
Orange and Rockland Utilities	
Gas Operations	Case No. 91-G-128, 92-G-0050
Palisades Generating Company	ER89-256-000/ER90-333-000
Pennichuck Water Co., Inc.	Docket No. DR85-2
Pennsylvania-American Water Company	Docket No. R-880916, R-891208 R-932670
Pennsylvania-Gas & Water Co.	
Gas Utility Operations	Docket No. R-832475, R-891261
Water Utility Operations	Docket No. R-850178
Pennsylvania Power Co.	
Retail Operations	Docket No. R-811510 R-842740, R-850267, R-870732
Wholesale Operations	Docket No. ER81-779
Pennsylvania Power & Light Company	
Retail Operations	Docket No. R-80031114
Wholesale Operations	Docket No. ER88-545-000
Philadelphia Electric Co.	
Wholesale Operations	Docket No. ER86-622-000, ER91- -000
Gas Operations	Docket No. R-870269
Philadelphia Gas Works	1988-89 Rates

Philadelphia Suburban Water Company	Docket No. R-870840, R891270 R-901667, R-911892, R-922476 R-932868
Poconos Sewer Company	Docket No. R-80011060
Poconos Water Company	Docket No. R-80011059
Providence Gas Company, The	Docket No. 1971
Quaker State Telephone Co.	Docket No. R-822277
Riverton Consolidated Water Co.	Docket No. R-842675, R-850153
Rockland Electric Company	Docket No. ER91030356J
SES Gloucester Co., LP	Docket No. SE851984
South Jersey Gas Company	Docket No. GR94010002
Southern Indiana Gas and Electric Company	
Gas Operations	Cause No. 39593
Electric Operations	Cause No. 39871
Spring Valley Water co., Inc.	Case No. 28374, 28734, 89-W-1151, 92-W-0045
Stamford Water Co.	Docket No. 91-01-03
UGI Corporation	
Gas Division	Docket No. R-811488, R-821899, R-832331
Electric Division	Docket No. R-80091303 R-811725, R-922195, R-932862
Warwick Valley Telephone Co.	
New Jersey Operations	Docket No. 831-38
New York Operations	Case No. 28535
Water and Supply Company Inc.	P.S.C. Docket No. 806
West Keansburg Water Co.	Docket No. 7710-1026, 801-55
West Penn Power Company	Docket No. R-78100685, R-80021082
West Virginia Telephone Co.	Case No. 82-192-T-42T
Western Massachusetts Electric Company	D.P.U. Case Nos. 85-270, 86-280
Western Pennsylvania Water Company	Docket No. R-832381, R-842621, R-850096, R-860397, R-870825
Wheeling Power Co.	91-1069-E-GI
Wisconsin Public Service Corp.	Docket No. ER83-655

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I am the consultant to the New York Chapter of the National Association of Water Companies which represents the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509).

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

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

I am a member of The National Society of Rate of Return Analysts and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conference
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association

February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

COMPARABLE EARNINGS APPROACH

In order to identify the appropriate return on equity for a utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be non-regulated companies so that circularity is avoided. Since utilities must compete with non-regulated firms in the capital markets, it is appropriate, if not necessary, to view the returns experienced by firms which operate in competitive markets.

To identify the comparable risk companies, the Value Screen Data Base was used to screen for firms of comparable risks. The Value Screen Data Base includes data on approximately 1600 firms. Value Line's risk analysis of these firms includes a wide range of financial and market variables. In order to conduct a comparable earnings analysis, categories of comparability were established to include Timeliness, Safety Rank, Financial Strength, Price Stability, Beta, and Technical Rank. The Value Line definitions (from the Value Line Investment Survey - Subscribers Guide) for each measure of comparability are:

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.

Financial Strength

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

Price Stability Index

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

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market.

> Investors should use the Technical and Timeliness Ranks as complements to one another.

One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved or expected to be achieved since the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. As established in the Hope case:

> "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Therefore, it is important to identify the returns earned by firms which complete for capital with utilities. This can be accomplished by analyzing the returns for non-regulated firms which are subject to the competitive forces of the marketplace.

The companies selected from the Value Screen Data Base have six categories of comparability which were designed to reflect the risk of PP&L and the Barometer Group. Value Line data was relied upon since it provides a comprehensive basis for evaluating the risks of the comparable firms. Further, since many of the factors, especially Timeliness, Safety Ranking, Financial Strength, Price Stability, Beta, and Technical Rank are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service, it is, therefore, an appropriate data base for measuring the investor perceived comparable return opportunities.

APPENDIX C TO THE DIRECT TESTIMONY OF PAUL R. MOUL

DISCOUNTED CASH FLOW ANALYSIS

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.

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.

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. One common investment horizon is 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:

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

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

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

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

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

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

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This

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[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 exposited the DCF model in its present form nearly two decades earlier.

DCF equation can be easily solved as:

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

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

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

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a 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 expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

<u>Use of DCF in Utility Ratesetting</u>

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

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

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

Dividend Yield

The historical annual dividend yields for PP&L and the Barometer Group are shown on Schedules 1 and 2, respectively. The 1989-1993 five-year average dividend yield was 6.6% for PP&L and 7.3% for the Barometer Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 8. 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 four business days before the record date of the dividend (i.e., the date 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 rateably 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.

As noted in the direct testimony, there has been a clear upward trend in public utility dividend yields since the fourth quarter of 1993. This is shown by the progressively higher average dividend yields. To recognize this trend, an 8.25% dividend yield has been used for PP&L and a 7.75% dividend yield has been used for the Barometer Group to account for the prospective orientation of the public utility ratesetting process.

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.

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

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

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.000% (4.00% × .5) for PP&L and for the Barometer Group, which assumes that two dividend payments will be a the expected higher rate during the initial investment period. Using the representative dividend yield of 8.25% as a base, the prospective (forward) dividend yield would be 8.42% (8.25% x 1.02000) for PP&L and 7.91% (7.75% × 1.02000) for the Barometer Group.

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

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a 8.46% (8.25% x 1.02488) dividend yield for PP&L and a 7.94% (7.75% × 1.02488) dividend yield for the Barometer Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

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

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

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

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

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 2.0625% (8.25% ÷ 4) for PP&L and was 1.9375% (7.75% ÷ 4) for the Barometer Group. The compound dividend yield would be 8.60% (1.02083^4 - 1) for PP&L and 8.06% (1.01957^4 - 1) for the Barometer Group recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For PP&L, a 8.49% forward-looking dividend yield is the average (8.42% + 8.46% + 8.60% = 25.48% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0(1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth. Similarly, the forward-looking dividend yield is 7.97% (7.91% + 7.94% + 8.06% = 23.91% ÷ 3) for the Barometer Group.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. Since stocks are not held forever by investors, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. This is because the traditional form of the DCF assumes no change in the price-earnings multiple, and as such the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

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

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("I/B/E/S"), a service of Lynch, Jones & Ryan, a New York Stock Exchange member securities brokerage firm. The I/B/E/S service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The earnings estimates are obtained from over 2,000 financial analysts from approximately 100 stock brokerage research departments. Forecasts are also provided by 26 institutions whose securities analysts are projecting earnings for companies in the I/B/E/S universe of companies. Mean and median earnings per share estimates along with various supporting data, such as number of analysts' estimates and range of estimates for each company's current and next fiscal years, are provided by the I/B/E/S service. Also included in the I/B/E/S reports are data regarding the mean and median of the contributing analysts' forecasts of each company's five-year earnings growth rate along with the number of analysts making forecasts, high-low range, and standard deviation of the forecasts.

In addition, Standard & Poor's publishes a monthly service which also provides a consensus of earnings estimates. The S&P Earnings Guide covers 3000 publicly traded stocks from over 1,600 financial analysts representing more than 130 brokerage firms nationwide. Those forecasts include current year and next year earnings estimates (mean, high, low and number of estimates) and five-year projected earnings per share growth rate.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, I/B/E/S, S&P, and Value Line show estimates of 1994 earnings and projections of 1995 earnings. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the 1995 earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2] equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. Earnings per share and dividends per share, represent the principal financial variables which influence investor growth expectations.

The bar graphs provided on Schedule 9 shows the historical growth rate in earnings per share published by I/B/E/S and Value Line for PP&L and the average for the Barometer Group. Schedule 9 also provides the Value Line historical growth rates in dividends per share, book value per share, and cash flow per share.

The historical growth rates in earnings per share contain some instances of negative values. Obviously, negative growth rates provide no reliable guide to gauge investor expected growth for the future. Investor expectations always encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, negative growth rates should not be given significant weight when formulating a composite investors' growth expectation for the future. The prospect of rate increases granted by regulators and the continued obligation to provide service as required by customers mandate investor expectation of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Because in the long-run investors

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[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.

will always expect positive growth, negative values will not provide a reasonable representation of future growth expectations. This is because while investors have knowledge that negative growth and losses can occur, their expectations always include positive growth. Rational investors always expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

The historical earnings per share growth rates were broadly dispersed for PP&L. Generally, though, the PP&L historical measures of growth reflecting earnings per share, dividends per share, book value per share, and cash flow per share exceeded the Barometer Group historical growth measures. The Barometer Group's historical earnings per share growth contain negative values which suppress the average growth rates. Negative growth is not meaningful in formulating expectations for the future. Recognizing that negative growth rates do not reasonably represent investor expectations for the future, the historical rates of changes in earnings per share for the Barometer Group must be substantially discounted. Historical dividend growth was about 3.50% for PP&L, while the range was lower (i.e., 2.25% to 3.31%) for the Barometer Group. Book value per share growth has been between earnings per share growth and dividend per share growth for PP&L and the Barometer Group historically.

Schedule 10 shows both long-run and short-run earnings per share growth rates calculated from the forecasts provided in the I/B/E/S, S&P, and Value Line publications. The I/B/E/S and S&P forecasts are restricted to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share and cash flow per share have also been included on Schedule 10.

Projected growth rates which influence investor expectations are indicated by the I/B/E/S, Standard & Poor's, and Value Line forecasts. Although long-run forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provide earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts. As reported on page 3 of Schedule 10, the 1995 earnings per share growth rates should also be considered when formulating an estimate of the DCF growth rate. These forecasts show two instances of negative growth rates for PP&L. The short-term earnings per share growth rates are very low the range of 0.90% to 1.30% for the Barometer Group. As to five year forecast growth rates, pages 1 and 2 of Schedule 10 indicate that the projected earnings per share growth rates are 1.00% to 1.55% for PP&L while the range is 2.28% to 3.56% for the Barometer Group. This situation indicates that the forecast show a repositioning of growth for PP&L relative to the Barometer Group. So while PP&L historically had higher growth than the Barometer Group, the forecasts now suggest that PP&L's growth will lag the Barometer Group. This situation is understandable given the extended length of time since the Company's last rate case. When the Company's earnings are restored to more normal levels after this rate case, PP&L will be able to begin a new cycle of earnings growth after the recent periods where growth has showed from formerly higher levels.

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

RISK PREMIUM ANALYSIS

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

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

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. While long-term debt cost rates may not change precisely with the changing annual rate of inflation, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation plus an increment to reflect investor perception of the future rate of inflation which may be expected over the term of the issue, as well as the risk associated with each rating category. It is important to note that the expected rate of inflation reflected in bond yields can be, and is today, quite different from the prevailing rate of inflation. Investors in long-term corporate bonds require compensation for inflation expectations associated with the investment horizon represented by the term of the issue. The demand for credit is another significant factor to be considered when viewing the trend in bond yields.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k = i + RP$$

where, the cost of equity ("***k***") is equal to the interest rate on long-term corporate debt ("***i***"), plus an equity risk premium ("***RP***") which represents the additional compensation for the riskier common equity.

Interest Rates

Federal Reserve Board ("Fed") policy actions substantially affect investor sentiment in the fixed-income securities market. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates.

As background to the selection of a public utility debt cost rate, the history of interest rate trends shows that the Fed began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the 1990-91 recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. In addition, the Clinton Administration initiated several bold proposals to deal with future borrowings of the government. While the markets' initial assessment of the economic plan of President Clinton was positive, the long-term implications of this plan are unclear. With lower expected federal deficits and reduced Treasury borrowings, together with limitations on the supply of new 30 year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough in October 1993 of 5.78%.

On February 4, 1994, the Fed increased the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves) from 3% to 3.25%, the first increase in short-term rates in five years. A second and third increase of one-quarter percentage point in the Fed Funds rate occurred on March 22, 1994 and April 18, 1994 when a higher 3.75% rate was established. A fourth increase of one-half percentage point in the Fed Funds rate occurred on May 17, 1994. This resulted in a 4.25% Fed Funds rate and a discount rate of 3.50% which was also increased by one-half percentage point at that time. Another rate increase occurred on August 16, 1994 when a higher 4.75% Fed Funds and 4.00% discount rate was established. A sixth increase in short-term interest rates occurred on November 15, 1994 when a 5.50% Fed Funds rate and a 5.00% discount rate was set. This increase in the Fed Funds and discount rate of three-quarters percentage point (0.75%) represented one of the larger increases in recent years. Prior to its February 1994 action raising short-term interest rates, the Federal Funds rate remained essentially unchanged for seventeen months, having been targeted at 3% on September 4, 1992. Also, the discount rate had remained at 3% for twenty-two months prior to the series of increases which occurred in 1994. These increases in short-term rates since the beginning of 1994 were 2.50% in Fed Funds and 2.00% in the discount rate. Increases in short-term interest rates have caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Since the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers which immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas to no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detract from the risk analysis, since the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principle, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 12 provides the historical holding period returns for the S&P Public Utility Index and S&P Industrial Index which have been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in the Ibbotson & Sinquefield study. The tabulation begins with 1928 since the earliest monthly dividend yield for the S&P Public Utility Index begins with January 1928. All reliable data for this study have been considered so as to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

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

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated public utility rate setting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in setting public utility rates since they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications, such as Standard & Poor's Corporation, The Value Line Investment Survey, Institutional Brokers Estimate System and brokerage reports.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix E, the long-term cost of capital in public utility raté cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. The risk premiums for each class of equity are:

	S&P Composite	S&P Industrials	S&P Public Utilities
Arithmetic Mean	6.10%	6.50%	5.33%
Geometric Mean	4.41%	4.56%	3.43%
Median	9.63	10.34	6.90
Midpoint of Range	7.02%	7.45%	5.17%
Average	6.56%	6.97%	5.25%

The empirical evidence suggests that the common equity risk premium is greatest for the S&P Industrial Index, while the S&P

Composite Index had slightly lower risk premiums. The S&P Public Utilities had the lowest risk premiums.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations the results provided on page 2 of Schedule 12 should also be considered. One of these sub-periods included the 42-year period, 1952-1993. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities. This period contained an historical rate of inflation (4.2% as measured by the Consumer Price Index) and economic growth (3.0% in real Gross National Product) which conforms more nearly with long-run economic expectations.

A further investigation was undertaken to determine whether a realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 1993 and 1979 through 1993 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 42-year, 20-year and 15-year periods, the public utility risk premiums were 6.24%, 5.39%, and 5.73% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 12.

APPENDIX E TO THE DIRECT TESTIMONY OF PAUL R. MOUL

CAPITAL ASSET PRICING MODEL

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

The CAPM theory has several unique assumptions which are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted with regard to testing the validity of some of the underlying assumptions of the model. Some of the tests would indicate, by using historical data, that the model may be potentially misspecified. By that I mean, these studies indicate that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Sometimes it has been argued that diversifiable (unsystematic) risk is unimportant to investors. But such a contention cannot be totally accepted in a utility rate case because business and financial risk of an individual utility, as well as regulatory risk are widely discussed within the investment community and certainly are a consideration to investors in public utilities.

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

$$k = Rf + \beta\ (Rm - Rf)$$

Recognizing that the traditional CAPM theory may misspecify the cost of equity, I have utilized a variation of the CAPM theory to account for this potential understatement. As I previously indicated, academic research has shown that for equities with a beta of less than 1.0 the traditional CAPM theoretical market line will understate the empirical market line. When tests were performed on the CAPM theory, the empirical evidence found that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. Unlike the traditional CAPM, empirical test indicate that portfolios with a zero beta required a higher return than the traditional CAPM theory would support. In addition, the tests of the CAPM theory indicated that companies with betas above 1.0 had returns lower than that indicated by the CAPM theory.

In order to recognize these empirical results, I have employed a variation of the traditional CAPM theory identified as the "zero-beta" model. The zero-beta CAPM employs similar inputs which are used in the traditional CAPM theory. The CAPM formula has been modified to express the model as:

$$k = Rf + 0.5\ (Rm - Rf) + 0.5\ (Rm - Rf)\beta$$

Here, the market premium has been segmented into two parts. One-half is combined with the risk-free rate of return and represents the return on a zero beta portfolio (i.e., Rf + 0.5 (Rm - Rf) = Rz). The remaining half of the market premium is adjusted for systematic risk. Hence, the zero-beta CAPM can be expressed as:

$$k = Rz + \beta\ (\ Rm - Rz\ )$$

Once again, I should state that both versions of the CAPM assume that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

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

Page 1 of Schedule 13, provides the coefficients of determination and the adjusted betas published by Merrill Lynch and Value Line. By way of explanation, the Merrill Lynch beta coefficient is derived from a "straight regression" based upon the percentage change in the monthly price of common stock and the percentage change monthly of the S&P 500 Index using a five-year period. The raw historical beta is adjusted by Merrill Lynch for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Merrill Lynch provides the R^2 which indicates the percent of price fluctuations on the stock which can be attributed to fluctuations on the S&P 500 Index. Value Line uses a similar approach and adjustment procedure to calculate its betas. The primary difference in the Value Line approach involves the use of weekly prices and the New York Stock Exchange Composite Average in place of the S&P 500 Composite Index. Neither Merrill Lynch or Value Line considers dividends in the computation of their betas.

Risk-Free Rate of Return

Regarding the risk-free rate of return ("Rf"), I have analyzed the yields on the broad spectrum of Treasury Notes and Bonds. The historical average yields are shown on page 2 of Schedule 13. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

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

In my opinion, 30-year Treasury Bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. In the zero-beta form of the model, I have used the yield on 10-year Treasury Notes. Very short term yields on Treasury bills should be avoided for several reasons. First, utility rates should be set on the basis of financial conditions which will exist during the effective period of the proposed rates. Second, 91-day Treasury Bill yields are more volatile than longer-term yields and are greatly influenced by Fed monetary policy. In the recent past, the steep upward sloping yield curve shows the inadequacy of short-term Treasury Bill yields. This is because short-term rates react to Fed policy moves which have been influenced by the recent political and economic situations. Moreover, Treasury Bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return ("Rm - Rf"). As one measure of the market premium, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to The Value Line Investment Survey Summary and Index (see page 5 of Schedule 13, the total return on the universe of Value Line equities is:

	Median Dividend Yield	+	Median Appreciation Potential	=	Total Return
As of November 18, 1994	2.6%	+	14.19%[1]	=	16.79%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. With the 16.79% total market return and the 8.00% risk-free rate of return, a 8.79% (16.79% - 8.00%) market premium would be indicated using the Value Line source.

On page 6 of Schedule 13, I have provided the rates of return from long-term historical time periods which have been widely circulated among the investment and academic community over the past several years. This data is published by Ibbotson Associates in its <u>Stocks, Bonds, Bills and Inflation</u> ("SBBI") 1994 Yearbook. From these data, I calculate a market premium using the common stock arithmetic mean returns less government bond arithmetic mean returns. For the period 1926-1993, the market premium was 6.9% (12.3% - 5.4%). I should note that the arithmetic mean must be used in the CAPM because it is single period model. Moreover, as Ibbotson has indicated:

> "Difference of Means: Interpretation. For use as the expected equity risk premium in the CAPM, the arithmetic or simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, not geometric, subtraction..." (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 114-115)

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[1] The estimated median appreciation potential is forecast to be 70% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 14.19% (i.e., $1.70^{.25}$ - 1).

For the CAPM, a market premium of 7.85% (6.9% + 8.79% = 15.69% ÷ 2) would be reasonable which is the average of the 6.9% using historical SBBI data and a market premium of 8.79% using Value Line forecasts.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 13

Direct Testimony of Thomas S. LaGuardia

Docket No. R-00943271

DIRECT TESTIMONY OF THOMAS S. LAGUARDIA
ON BEHALF OF
PENNSYLVANIA POWER & LIGHT COMPANY

Q. **Please State Your Name And Business Address.**

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752

Q. **What Is Your Occupation?**

A. I am President of TLG Services, Inc. (TLG)

Q. **What Is The Business Of TLG?**

A. TLG provides engineering and field services for nuclear and fossil-fueled generating stations.

Q. **What Are Your Responsibilities With TLG?**

A. I am responsible for the technical and business management of engineering and field services in the areas of decontamination, decommissioning, waste management and general engineering for nuclear and fossil-fueled generating stations.

Q. **What Is Your Educational And Professional Background?**

A. I completed my Bachelor of Science in Mechanical Engineering at Polytechnic Institute of Brooklyn in 1962 and my Master of Science in Mechanical Engineering at the University of Connecticut in 1968. I am a registered Professional Engineer in Connecticut (No. 10393), New York (No. 059389) and New Jersey (No. 38193). I founded TLG in April, 1982. I was employed by Nuclear Energy Services in Danbury, Connecticut, from 1973 until I founded TLG. My prior employment was with Gulf Nuclear Fuels Corporation (formerly United Nuclear Corporation [UNC]) and Combustion Engineering.

Q. What Is the Purpose Of Your Testimony?

A. The purpose of my testimony is to present the results of the dismantling cost studies prepared by TLG for the following fossil-fueled power plants owned and operated by Pennsylvania Power & Light Company (PP&L):

Station	No. of Units	Station Megawatts
Holtwood 15&16	2	(retired)
Holtwood 17	1	72 MWe
Sunbury 1&2	2	85 MWe
Sunbury 3	1	110 MWe
Sunbury 4	1	145 MWe
Martins Creek 1&2	2	150 MWe
Martins Creek 3&4	2	820 MWe
Brunner Island 1&2	2	344 MWe
Brunner Island 3	1	754 MWe
Montour	2	750 MWe

I am also presenting the results of the 1993 decommissioning cost study prepared for the Susquehanna Steam Electric Station (Susquehanna SES) by TLG.

The fossil and nuclear decommissioning cost studies have been identified as Exhibits TSL 1 and TSL 2, respectively.

Q. Please Summarize The Costs Identified In Both The Fossil And Nuclear Decommissioning Studies.

A. Dismantling and demolishing of the aforementioned fossil-fired steam electric generating stations was estimated to cost approximately $628.5 million (1994) dollars. The fossil estimate addressed all 16 units at the five sites and included the razing of site structures to grade. Each site was decommissioned upon the cessation of the final unit's operation. Costs were specifically identified for the remediation of asbestos, which is found throughout many of the units. A credit was included for the potential value of the scrap steel and copper generated in the dismantling process.

Decommissioning of the two nuclear units at the Susquehanna Steam Electric Station was estimated to cost approximately $804 million (1993) dollars. The study assumes that the units will complete their fully licensed operating lives and that the station will be completely dismantled following the removal of radioactivity. Low-level radioactive wastes were destined for a future facility within the Appalachian Compact while spent fuel was assumed to be transferred to the Department of Energy's geologic repository within approximately five years of plant shutdown.

Q. What Is Covered By The Term "Decommissioning" As Used With Reference To Generating Stations?

A. Decommissioning is the planned and orderly retirement of a generating station. In the case of nuclear plant decommissioning, it requires the complete removal and controlled disposal of radioactive materials to levels prescribed by the U.S. Nuclear Regulatory Commission (NRC), and termination of the NRC license. The utility may then dismantle the remaining clean systems and structures.

In the case of a fossil-fueled power plant, upon retirement the facility may either be rendered safe indefinitely (through on-going maintenance, repair and security measures), or dismantled. A specific discussion of public safety and dismantling is included later in this testimony.

Q. Do You Have Experience In The Design And Construction Of Fossil-Fueled Generating Stations?

A. Yes. During my employment with Combustion Engineering, Inc. from 1962 to 1968, I was a boiler design, performance and construction engineer for 500 megawatt electric (MWe) coal fired power boilers, and merchant and Naval oil fired marine boilers.

Q. What Decommissioning Experience Do You Have?

A. My decommissioning experience began as site representative for UNC during the BONUS reactor decommissioning in 1969 and 1970. BONUS was a 17 MWe demonstration power reactor located in Puerto Rico, owned by the U.S. Atomic Energy Commission (USAEC), now the U.S. Department of Energy (USDOE), and operated by the Puerto Rico Water Resources Authority. It was the largest reactor decommissioned by entombment up to that time. The program involved extensive chemical decontamination of radioactive systems, selective piping and component removal, and entombment of the reactor vessel within a massive concrete barrier. The entombment has a design life of 125 years. My role as site representative was to act as a technical liaison and provide project engineering and schedule management assistance during system decontamination, component removal, vessel entombment and facility close-out.

Following the BONUS program, I was lead engineer for UNC during the Elk River Reactor decommissioning between 1970 - 1974. Elk River was a 20 MWe demonstration power reactor located in the state of Minnesota, owned by the USAEC and operated by United Power Association. Elk River was decommissioned by complete dismantling. The program involved segmentation of the reactor vessel and internals using remotely operated cutting torches, as well as the packaging, shipping and controlled burial of the segments.

Similarly, radioactive piping and components were removed, packaged, shipped and buried. Radioactive concrete was demolished by controlled blasting, and nonradioactive concrete demolished by wrecking ball to completely dismantle the facility. Initially, my role for UNC was Consulting Engineer and later Lead Engineer for UNC technical support for on-site activities.

I was Project Engineer for the detailed engineering and planning of the Shippingport Station Decommissioning Project from 1979 - 1982. Shippingport was a 72 MWe light water breeder reactor located in the state of Pennsylvania, owned by the USDOE and operated by Duquesne Light Company. The facility is now dismantled, and TLG, with its joint venture partner, Cleveland Wrecking Company, dismantled all of the clean and contaminated piping and components and removed contaminated concrete. My role for TLG/Cleveland was Project Director, and I selected and managed an on-site project management team to hire and supervise work crews to accomplish the dismantling. Our work is complete and was performed on schedule and within budget.

I also assisted Atomic Energy of Canada, Ltd. in the detailed engineering and planning for the decommissioning of the 238 MWe Gentilly Unit 1 reactor located in Three Rivers, Canada. My role was to provide overall decommissioning consulting services and detailed cost estimation of alternatives.

TLG worked with the Northern States Power Company between 1988-89 in the preparation of the decommissioning plan for the Pathfinder Atomic Power Plant. Pathfinder, located in Sioux Falls, S.D., was a 60 MWe reactor initially placed in a safe storage condition (SAFSTOR) after an abbreviated operating life. TLG prepared detailed cost and schedule estimates, and vessel activation estimates, analyzed the reactor vessel to be used as its own shipping container, and prepared the decommissioning plan in support of plant decommissioning.

TLG continues to assist the Sacramento Municipal Utility District with the decommissioning planning for the Rancho Seco Nuclear Generating Station. This work, ongoing since 1989, has included a detailed reactor vessel activation analysis, preparation of decommissioning alternative cost and schedule estimates, and assistance with the preparation of the decommissioning plan.

TLG assisted the Long Island Lighting Company in the decommissioning of the Shoreham Nuclear Power Station. This work included the preparation of a detailed reactor vessel activation analysis, cost estimates, schedules, management organization, waste volume estimates and preparation of a draft decommissioning plan.

TLG was selected by Cintichem, Inc. (a subsidiary of Hoffman-LaRoche) as Decommissioning Co-Managers of a 10 megawatt (MWt) thermal research reactor and associated hot cells and facilities. TLG's staff prepared a reactor core activation analysis, and a cost and schedule estimate for the project. TLG assisted in the preparation of the decommissioning plan which has received Nuclear Regulatory Commission (NRC) approval. TLG's field management staff is on-site assisting in the project management and supervision of the work crews in decommissioning and dismantling the facility. My role in the project is Senior Decontamination and Decommissioning Expert on the Nuclear Safeguards Committee.

TLG is also currently involved in the engineering and planning activities associated with the decommissioning of the Yankee Rowe, Trojan Nuclear Plant and Big Rock Point nuclear units. This work includes activation analyses, preparation of decommissioning alternative cost and schedule estimates, and assistance with the preparation of the decommissioning plans. In addition, TLG has been selected to prepare the steam generators and the pressurizer at Trojan for transport to the burial facility at Richland, WA. TLG will be responsible for certifying package integrity, overseeing the grouting of the components and preparing any supporting transportation analyses.

Q. Have You Prepared Or Co-authored Any Studies And Reports On Decommissioning Cost Estimating And Technology?

A. Yes. While at Nuclear Energy Services, I was Principal Investigator for the Atomic Industrial Forum National Environmental Studies Project (NESP) decommissioning study entitled "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives" (AIF/NESP-009). This study evaluated the costs, schedules and environmental impacts of decommissioning 1100 MWe reactors (Pressurized Water Reactors [PWRs], Boiling Water Reactors [BWRs], and High Temperature Gas Reactors [HTGRs]).

I also co-authored the "Decommissioning Handbook" for the USDOE. The Handbook reported the state-of-the-art in decommissioning technology (as of 1980), including decontamination, piping and component removal, vessel segmentation, concrete demolition, cost estimating and environmental impacts.

At TLG, I co-authored "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (AIF/NESP-036) for the Atomic Industrial Forum, National Environmental Studies Project. The Guidelines identify the elements of costs to be included in the estimation of decommissioning activities for each of the principal decommissioning alternatives. Specific guidance in cost estimating methodology and reference cost data is provided in this study. The major objective of this study is to provide a basis for consistent cost estimating methodology.

TLG also prepared a study, which I co-authored, entitled, "Identification and Evaluation of Facilitation Techniques for Decommissioning Light Water Power Reactors" (NUREG/CR-3587) for USNRC. The study evaluated the costs and benefits of techniques to reduce occupational exposure and waste volume from decommissioning. In addition, TLG prepared the Decommissioning Plans (DP) for Dresden Unit 1, Pathfinder and Cintichem reactors, and the Environmental Reports (ER) for Dresden Unit 1 and Indian Point Unit 1.

Under my supervision and direction, TLG has prepared site-specific decommissioning studies for most of the nuclear units in the United States and 43 fossil-fueled power plants. TLG personnel authored the paper "How to Determine the Cost of Dismantling a Fossil-Fuel Electric Power Plant," A. Carlstrom, Cost Engineering Magazine, April, 1989.

TLG was responsible for overseeing the dismantling and demolition of a fossil-fueled steam plant for a major Connecticut hospital facility. In connection with this demolition project, I participated in the site inspection and cost estimate development. The work was subcontracted and TLG personnel supervised the contractors.

Q. For What Utilities Has TLG Prepared Site-Specific Dismantling Studies Of Fossil-Fueled Power Plants?

A. In addition to the PP&L study, TLG has prepared site-specific dismantling studies for fossil-fueled power plants owned by:

Indianapolis Power & Light Company
Allegheny Power System
Kansas City Power & Light Company
Texas Utilities Company
Public Service Electric & Gas Company

Q. Has The NRC Approved Site-Specific Cost Estimates For Nuclear Units Utilizing TLG's Cost Estimating Methodology?

A. Yes. The NRC has reviewed TLG's cost estimating methodology. The NRC approved the decommissioning plan proposed by TLG for the Pathfinder Atomic Power Station. Funding provisions were based upon a site-specific estimate developed by TLG. Upon review of the cost estimate and supporting documentation, the NRC recommended TLG's "methodology" for its level of detail and comprehension, to another utility in the process of preparing a decommissioning estimate. TLG was also selected by the Long Island Lighting Company, and later by the Long Island Power Authority, and the Sacramento Municipal Utility District to develop site-specific cost estimates for inclusion in the decommissioning plans for the Shoreham Nuclear Station and the Rancho Seco Nuclear Generating Station, respectively. TLG also worked with Yankee Atomic Electric Company, Portland General Electric and Southern California Edison to develop the cost for decommissioning the Yankee Rowe Plant, Trojan Nuclear Plant, and San Onofre Nuclear Generating Station, respectively. Since these documents (plans) required NRC approval, these utilities have relied upon TLG cost studies because of TLG's experience and reputation in nuclear plant decommissioning and their acceptance with the NRC.

Q. Are There Any Regulations Or Codes Applicable To Dismantling?

A. Yes. The Building Officials & Code Administrators (BOCA) National Building Code, widely adopted by most states, including Pennsylvania, requires that retired structures may not be left in an unsafe condition. Specifically, Section 120.1, "Right to Deem Unsafe," states:

> *All buildings or structures that are or hereafter shall become unsafe, unsanitary or deficient in adequate means of egress facilities, or which constitute a fire hazard, or are otherwise dangerous to human life or the public welfare, or which involve illegal or improper use, occupancy or maintenance, shall be deemed unsafe buildings or structures. <u>All unsafe structures shall be taken down and removed or made safe and secure, as the code official deems necessary and as provided for in this section.</u> A vacant building, unguarded or*

open at door or window shall be deemed a fire hazard and unsafe within the meaning of this code.

(Emphasis Added)

A retired power plant fits this definition of an unsafe structure which must be taken down and removed or made safe and secure.

Q. Are There Any Federal Regulations Applicable to Nuclear Plant Decommissioning?

A. Yes. The NRC published the Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" in the Federal Register of June 27, 1988 (53 Fed. Reg. 24018) to establish technical and financial criteria for decommissioning licensed facilities. The decommissioning cost estimate prepared for Susquehanna SES fully satisfies the requirements set forth in this regulation.

Q. What Type Of Costs Are Analyzed In A Decommissioning Study?

A. There are three types of costs included and analyzed in a dismantling study: activity-dependent costs, period-dependent costs and collateral costs. Activity-dependent costs are those associated with the physical work of removing piping, components and structures and transporting and disposing of the same. These costs represent labor, materials and special services (subcontracted) costs associated with the work crews activities (hence, activity-dependent costs). The summation of the durations to perform these activities when properly sequenced provides the overall schedule for the project.

Period-dependent costs are those associated with the management staff costs which are necessary to provide technical and administrative direction to the project. These management costs must continue for the duration of the project. The project is divided into three periods: 1) Engineering Planning and Preparations; 2) Dismantling; and 3) Site Restoration. The management staff size is adjusted to reflect the crew size and work activities in each period. Accordingly, these staff costs are period-dependent.

Collateral costs are all those costs which are neither activity- nor period-dependent. They include insurance, taxes, permits, large equipment purchases and special tools.

Q. What Are The Major Differences Between Nuclear And Fossil Power Plants?

A. The major difference is the radioactivity inherent in nuclear power plants. Removal of radioactively contaminated piping, components and structures from a nuclear plant is more difficult and costly than for comparable items at a fossil plant. The activities of decontaminating, removing, packaging, shipping and burying radioactive materials from a nuclear plant require strict radiological controls, special containments and packaging, and licenses for the transport for disposal. There are many more opportunities for problems to arise in nuclear plant decommissioning than in fossil plants.

Fossil plants have no radioactivity, and so dismantling is comparable to reverse construction. There are fewer potential hazards for the worker and so productivity is higher overall than with nuclear plants, and the overall potential for problems is lower.

Q. Does Your Experience In The Decommissioning Of Nuclear Power Plants Aid In The Conduct Of A Site-Specific Dismantling Study Of A Fossil-Fueled Power Plant?

A. Yes. The parallelism in approach between nuclear plant decommissioning and fossil plant dismantling enables us to rely on the field experience from nuclear decommissioning to prepare fossil plant studies. In particular, the following major areas of planning and estimating exhibit similar characteristics.

1. Site Characterization

The process and planning for identification of radionuclide contamination composition and extent for nuclear power plants is similar to that required for potentially hazardous materials in fossil-fueled power plants.

2. Removal of Hazardous Material (Asbestos)

Planning and removal of asbestos-containing materials in nuclear and fossil plants is identical.

3. Sequencing of Work Activities

Identification and sequencing of essential (to the decommissioning task) and non-essential systems removal follows the same considerations in both types of plants. Essential systems include electric power, lighting, heating, ventilation and liquid processing systems. For example, power and lightning would be retained as long as possible to avoid bringing in temporary services prematurely.

4. Management Staff

Identification of utility and decommissioning (dismantling) staffing composition and levels follows the same process in both types of units. The specific job functions will differ but the logic is the same. Management staff costs are period-dependent; that is, they are a function of the overall project duration.

5. Removal of Non-Contaminated Equipment/Structures

Removal of non-contaminated piping, components and structures are activity-dependent. The methods for their removal are identical for most of the systems and structures in each type of plant. Piping diameters and lengths are essentially identical (size-for-size plants), and the removal rate will be the same. Clean components, such as feedwater heaters and pumps, condensate pumps, demineralizer systems, etc., in nuclear plants, are the same sizes and types found in fossil plants. Steel and concrete structures are removed in the same manner in both types of plants. Removal of equipment unique to fossil plants, such as coal handling and air cleaning systems, relates to the weight of sub-components, and is accomplished by rigging and segmentation.

6. Scheduling

The scheduling of work activities for either type of plant follows the proven planning techniques of activity precedence networks and critical path management. An activity precedence network is a flow diagram of sequenced activities based upon the priority or "precedence" of completing one or more activities before starting another activity. The critical path is the longest sequence of work activities in a precedence network from project initiation to completion.

7. Collateral Cost

Collateral costs are neither activity-dependent nor period-dependent costs. They include items such as engineering, energy, licenses, permits, and taxes, etc. These items are identical in both types of plants, although specific cost values will differ.

8. Contingency

Contingency, as described more completely later in this testimony, is a cost allowance for field-related problems that are likely to occur. These problems include tool and equipment breakdown, late deliveries of supplies and equipment, and adverse weather. These field problems occur in both nuclear and fossil plant dismantling, although the specific allowances differ in each case.

9. <u>Field Experience</u>

The field experience in both nuclear and fossil plant dismantling for clean equipment is essentially identical. Heavy lifts of components weighing 50 to 450 tons are common in both plant types, and the planning and implementation activities are virtually identical.

In summary, the nuclear plant decommissioning experience is directly applicable to fossil plant dismantling.

Q. How Does This Estimating Process Differ From Construction Estimating?

A. There is very little difference in the elements of cost between fossil plant dismantling and construction. Both activities must account for labor, materials, equipment, services and collateral costs (as defined earlier). The activities related to construction are similar to those for dismantling. Specifically, construction activities such as rigging components into position and welding connecting piping are comparable to dismantling activities such as cutting connecting piping and rigging components out of the structures. In the case of construction however, the pipe welds must be inspected by non-destructive methods (such as X-Ray examination), and cut out and re-welded if flaws in the weld are identified. This re-work causes schedule delays and incurs additional expense. In the case of dismantling, the pipe need only be cut once. Problems in dismantling occur when plant drawings and specifications do not properly reflect the plant as constructed. This occurs when changes to the plant are made that have not been recorded on the as-built drawings. This can result in additional dismantling costs. However, in general fossil dismantling estimating is comparable to construction cost estimating.

Q. Were The Decommissioning Studies Contained In Exhibits TSL 1 and TSL 2 Prepared Under Your Direction And Supervision?

A. Yes. I developed the basic methodology used at TLG to estimate the costs to dismantle both nuclear and fossil-fueled power plants. I trained my engineering and estimating staff in this methodology.

With respect to the estimates prepared for PP&L, I personally inspected each of the power stations with the TLG staff assigned to this project. This included an inspection of the power blocks, turbine-generators, condensate and feedwater systems, and the fuel handling and pollution control systems. The purpose of these inspections was to familiarize myself and the TLG staff with the site-specific features of each unit so that the drawings and specifications used in the estimate would be better understood at the engineering offices of TLG. During the preparation of the cost estimate details, I provided guidance and interpretation to the TLG staff on how to estimate specific areas of the units. I reviewed the results of each plant cost estimate to ensure the results were reasonable and representative of the features of each unit. Finally, I supervised the preparation of the report summarizing the results of the estimate.

Q. What Procedures Were Used For The Decommissioning Studies?

A. The studies were developed using the detailed engineering drawings, together with plant description and physical inventory documents. These drawings and documents were used to identify the general arrangement of each facility and to determine estimates of building concrete volumes, steel quantities, numbers and size of components and degree of site restoration required.

For the fossil studies, selected reference boiler units were chosen to characterize comparable boilers. The remainder of the site was characterized for each station. The combination of the number of each type of boiler plus the inventory of the remainder of the site provides a complete inventory of the station.

The TLG staff made site inspections of each plant. The on-site inspections included investigation of the access to remove components, and movement of heavy equipment (cranes, forklifts, front-end loaders) close to the structure for demolition and removal work.

Dismantling is a labor-intensive program. Representative labor rates for the local area in which the plant is located and each craft or salaried work group are essential for development of a meaningful site-specific dismantling cost estimate. The TLG studies used typical craft labor rates and utility salary data for the area provided by PP&L. I consider the use of such labor cost information reliable and appropriate for the purposes of the studies.

Q. What Methodology Was Used To Prepare The Estimates?

A. The methodology used to develop the cost estimates followed the basic approach presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," the USDOE "Decommissioning Handbook" and the American Association of Cost Estimators paper "A Methodology for Determining the Cost of Dismantling Fossil-Fueled Electric Power Plants." The basic methodology described in these documents for preparing dismantling estimates is widely accepted by the electric power industry and regulatory commissions throughout the United States and is applicable for nuclear as well as fossil plants.

Q. How Was This Methodology Applied To The PP&L Plants?

A. The aforementioned references use a unit cost factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit cost factors for activities such as concrete removal ($/cu yd), steel removal ($/ton), and cutting costs ($/in) were developed from the labor information provided. Consumable material and equipment rental costs (crane and truck rental, operating costs for heavy equipment, torch cutting gas consumption, etc.) were taken in large part from R.S. Means, "Building Construction Cost Data." The activity-dependent cost for removal, shipping and disposal were estimated using the item quantity (cu yds, tons, inches, etc.) developed from plant drawings and inventory documents. The activity duration critical path derived from such key activities as nuclear steam supply or boiler removal, turbine removal etc., was used to determine the total dismantling program schedule.

The program schedule is used to determine the period-dependent costs such as program management, administration, field engineering, equipment rental, and security. The salary and hourly rates are typical for personnel associated with period-dependent costs.

In addition, collateral costs were included for heavy equipment rental or purchase, safety equipment and supplies, energy costs, permits, taxes, and insurance.

The activity-dependent, period-dependent, and collateral costs were added to develop the total dismantling costs. An average contingency was added to allow for the effect of unpredictable program problems on costs. Such a contingency is appropriate for a project of this size and type. The total dismantling costs plus contingency, less any scrap credit provides the total project cost. One of the primary objectives of every dismantling program is to protect public health and safety. The cost estimate for the dismantling activities includes the necessary planning, engineering and implementation to provide this protection to the public.

Q. What Is The Basis For The Contingency?

A. The purpose of the contingency is to allow for the costs of high probability program problems, where the occurrence, duration, and severity cannot be accurately predicted and have not been included in the basic estimate. The inclusion of contingency in cost estimation for both construction and dismantling is well accepted. The American Association of Cost Engineers (AACE) (in their Cost Engineers Notebook) defines contingency as follows:

> *Contingency - specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur.*

Past dismantling and decommissioning experience has shown that these problems are likely to occur and may have a cumulative impact. Fossil-fueled and nuclear power plants share some of the same potential problems leading to the need for contingency in cost estimates. These problem areas include:

Schedule slippages:	leading to crew overtime payments and/or project extensions
Weather delays:	loss of productivity, overtime, slippages
Labor strikes:	loss of productivity, slippages
Workers injuries:	production interruptions, additional safety training, workers compensation claims, possible increased insurance premiums
Material shipping:	rescheduling of activities, out-of-scope backcharges from subcontractors

Equipment breakdowns:	rescheduling of activities, out-of-scope backcharges from subcontractors
Regulatory inspections:	insurance inspectors, Occupational Safety and Health Act (OSHA) inspectors, federal and state EPA inspectors, state building inspectors
Hazardous materials:	special handling requirements beyond planned requirements

Nuclear power plants additionally have to deal with the special handling requirements of radioactive materials for decontamination, removal, packaging, shipping and disposal. A more extensive discussion of nuclear contingency is included in the AIF/NESP-036 Guidelines Study (Chapter 13) referred to earlier.

In the AIF study, individual contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from our actual decommissioning experience. The overall contingency, when applied to the appropriate components of nuclear plant decommissioning costs, results in an average contingency of up to 25%.

For fossil plant dismantling, the absence of radioactive materials and their attendant potential problems simplifies the dismantling process. Individual activity contingency estimates for fossil-fueled power plants amount to an overall average of approximately 15% contingency.

Independent of our preparation of this estimate for PP&L, R.S. Means, "Building Construction Cost Data," suggests that a 15% contingency factor for conventional construction be used.

Q. How Do the Factors You Used Compare To Contingency Factors Adopted By Regulatory Commissions For Nuclear Plant Decommissioning?

A. As I discussed earlier, the nuclear contingency is generally not more than 25%. The Federal Energy Regulatory Commission (FERC) adopted a 25% contingency for nuclear power plant decommissioning as reasonable, following the ruling of Judge Liebman in the Middle South Energy/Grand Gulf Case (Docket ER82-616), decision issued February 3, 1984. Numerous state public utility commissions have adopted a 25% contingency for nuclear plant decommissioning, as evidenced by an American Gas Association-Edison Electric Institute Depreciation Committee Survey, which showed that at least 21 of 32 utility survey respondents had included a 25% contingency in their estimates. The survey also showed that of the 15 utilities who filed rate cases, 11 had approval to use the 25% contingency for their plant decommissioning studies.

Q. For Purposes Of The Estimate, When Did You Assume The Units At Each Site Would Be Dismantled?

A. For the fossil studies, we assumed dismantling of each unit would occur upon retirement of the last unit at each site. This approach is reasonable because it would be more difficult and costly to protect the operating units from potential damage when demolishing the retired units. Moreover, the dismantling staff and crew would only have to mobilize and demobilize once for the site instead of each time a unit is retired. Using the same staff and crew would take maximum advantage of the lessons learned as the units are dismantled in sequence.

The nuclear units were assumed to shutdown upon the expiration of their operating licenses. Decommissioning activities were coordinated between the two units at Susquehanna SES to the maximum extent possible. Spent fuel from Unit 1 was discharged to the Unit 2 pool enabling decommissioning activities to proceed in the Unit 1 Reactor Building immediately after defueling.

Q. How Was Scrap Or Salvage Credit Included In the Overall Estimate?

A. Credit for carbon steel, stainless steel and copper scrap was included in the overall fossil estimates based on current published scrap values.

No credit was included for salvage of any components, as these components will be of an obsolete design by the time these plants are dismantled. The labor cost to recover potentially salvageable materials (valves, pumps, motors, etc.), and to store, protect, package and ship them is not warranted. These materials were considered as scrap.

No positive value was assumed for the scrap generated in the decommissioning of the nuclear units primarily due to the off-setting expense of the surveying required to verify that material leaving the site has no detectable radionuclide contamination.

Q. Please Describe The Process Of Dismantling A Fossil Power Plant And How That Process Was Reflected In The PP&L Study.

A. Approximately three months prior to final shutdown, engineering and planning would begin on the preparation of the Dismantling Engineering Plan (Plan) and Environmental Report (ER). The Plan describes the status of the facility at shutdown, work to be accomplished, safety analyses associated with each of the major activities, general procedures and sequence to be followed, and final site condition upon completion of all work. Similarly, the ER would evaluate environmental effects to workers and the public, and waste generation effects on the site and environment. These documents would be submitted to the Environmental Protection Agency and other applicable regulatory agencies for review and approval, and authorization to proceed. The sequence of work would be envisioned as follows:

Period 1 - Site Preparations - would begin upon shutdown of the facility, and would involve site preparations to initiate dismantling. Fuel is assumed to have been burned prior to shutdown or transferred to another operating unit.

Period 2 - Dismantling Operations - would begin upon receipt of approval of all regulatory agencies. This phase of the work involves the removal of all components of the boiler, air quality treatment systems (electrostatic precipitators, flue gas desulfurization systems, etc.), fuel handling systems (coal conveyors, crushers, oil storage tanks, etc.), the turbine-generator, condensate and feedwater systems. In general, the boiler will be dismantled in a bottoms-up mode, whereby the lower sections of the boilers will be cut at grade level, and remaining upper sections lowered to grade or scaffolding erected to cut the upper sections of the boiler furnace. This method of dismantling is necessary for the top-hung type of boiler that is supported from the steel structure.

Care must be taken to ensure sections are removed uniformly from the bottom to avoid any unbalanced load on the steel structure that may cause it to become unstable.

Steel structures used to support the boiler and turbine-generator components will be dismantled by controlled demolition (by lowering sections to grade by cranes) to prevent injury to workers on lower floors. The steel structures will be dismantled from the top down, essentially reversing the construction sequence.

Concrete structures such as boiler foundations, floors, turbine-generator pedestals and support buildings will be demolished by conventional wrecking methods. These may include the use of wrecking balls, pneumatically-operated rams on a backhoe, or controlled blasting.

Period 3 - Site Restoration - would involve the re-grading of all areas that were disturbed by the dismantling process. Structures will be removed to three feet below grade to permit re-vegetation of the site, or to eliminate at-grade hazards. Clean rubble would be used on site for fill and additional soil would be used to cover each subgrade structure. The site would be graded and stabilized.

Q. Describe The Decommissioning Alternatives Delineated In The NRC Rule For Nuclear Utilities.

A. The supplemental information to the NRC Rule (53 Fed. Reg. 24022-23) describes three decommissioning alternatives as acceptable: DECON (prompt removal/dismantling), SAFSTOR (mothballing) and, under special circumstances, ENTOMB (entombment). They are defined as follows:

> **DECON** is the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits termination of the license and allows the property to be released for unrestricted use shortly after cessation of operations;

> **SAFSTOR** is the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit termination of the license and release for unrestricted use.

> **ENTOMB** is the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactivity decays to a level permitting termination of the license and unrestricted release of the property.

It should be noted, however, that the NRC provides that delayed decommissioning following initial mothballing or entombment activities should not exceed 60 years, unless it can be shown necessary to protect public health and safety (10 CFR 50.82 (b) (1)). This rule discourages the use of the ENTOMB alternative unless specific advantages can be shown (see 53 Fed. Reg. 24023-24). However, both the DECON and SAFSTOR alternatives are considered reasonable options for decommissioning Susquehanna SES.

Q. What Are Your Recommendations Regarding The Alternative Selection?

A. I recommend that, for planning purposes, the decommissioning cost funding be based upon removal of Susquehanna SES using the DECON alternative. This alternative provides the most reasonable means for terminating the license for the site in the shortest possible time. Furthermore, this alternative avoids the long-term costs and commitments associated with the maintenance, surveillance and security requirements of the conventional delayed dismantling alternatives.

The recommended alternative also allows use of the plant's knowledgeable current operating staff, a valuable asset to a well-managed, efficient decommissioning program. All equipment needed to support decommissioning operations such as cranes, ventilation systems and radwaste processing equipment would be fully operational. In addition, the site would be available for other use in the near term, with the exception of the area immediately surrounding the plant's fuel storage facility.

Q. Would You Describe The Process Of Decommissioning A Nuclear Power Reactor Utilizing The DECON Alternative?

A. Yes. In accordance with the NRC rule (10 CFR 50.75(f)), a licensee of a nuclear power reactor is required, at or about five years prior to the projected end of operation, to submit to the NRC a preliminary decommissioning plan. The preliminary plan is to contain a cost estimate for decommissioning and an up-to-date assessment of the major technical factors that could affect planning for decommissioning. This NRC rule requires the following factors, among others, to be considered in the plan:

1) Major technical actions necessary to carry out decommissioning safely;
2) The current status with regard to disposal of high-level and low-level radioactive waste;
3) Radioactive release criteria; and
4) Adjustments to funding levels to demonstrate a reasonable level of assurance that funds will be available when needed for decommissioning.

Approximately two years prior to final shutdown, engineering and planning would begin on the preparation of the proposed decommissioning plan (the "Plan") with a corresponding Environmental Report. In accordance with 10 CFR 50.82 (b), the Plan must describe:

1) the decommissioning alternative chosen and major activities involved;
2) controls and limits on procedures and equipment to protect occupational and public health and safety;
3) the planned final radiation survey;
4) an updated cost estimate with a comparison to present funds set aside and a plan for assuring the availability of adequate funds for completion of decommissioning; and
5) technical specifications, quality assurance provisions and physical security plan provisions in place during decommissioning.

The Plan must be submitted to the NRC for review and approval no later than one year prior to expiration of the NRC operating license, pursuant to 10 CFR §50.82 (a).

Three phases are involved in the DECON alternative as follows:

Period 1 - Site Preparations - This period begins upon shutdown of the facility, and involves site preparations to initiate decommissioning. The reactor would be defueled with the fuel placed in the spent fuel storage pool until it is cooled sufficiently to be transferred to DOE or an alternative storage facility. As noted earlier, transportation and disposal of spent fuel at a DOE facility is not considered part of decommissioning and no costs associated with these activities are included in the decommissioning estimates. (These expenses have been funded by the owner throughout the plant's operating life, payable to DOE for future rendering of these services.) However, the impact on the decommissioning schedule due to the presence of such material on-site has been addressed in the study through the schedule. Wastes remaining from plant operations would be removed from the site and all systems nonessential to decommissioning would be isolated and drained.

Period 2 - Decommissioning Operations - This period begins upon approval of the decommissioning plan from the NRC and the mobilization of the decontamination and dismantling workforce. This phase of the work involves the removal of radioactivity from the site and concludes with termination of the NRC operating license. The activities in this period include selective decontamination of contaminated systems, e.g., using aggressive chemical solvents to dissolve corrosion films holding radionuclides, thereby reducing radiation levels.

While effective, the on-site decontamination processes are not expected to reduce residual radioactivity to the levels necessary to release the material as clean scrap. Therefore, all contaminated components will have to be removed for controlled burial. However, decontamination will reduce personnel exposure and permit workers to operate in the immediate vicinity of most components, cutting and removing them for controlled disposition at a low-level radioactive waste burial facility.

Contaminated piping to and from major components will be cut and removed. Selected major components such as the steam generators, reactor recirculation pumps, heat exchangers, small tanks, etc., will then be removed intact and sealed so that they may be shipped as their own containers for disposal. Smaller components, such as sampling system pumps, filters, filter housings, strainers, etc., will be loaded into containers and shipped for burial.

The reactor vessel and its internals will be segmented and remotely loaded into steel liners for transport to the burial facility in heavily shielded shipping casks. The reactor vessel and internals will have sufficiently high radiation levels to require all cutting to be done underwater or behind heavy shields, using cutting torches operated by remote control to reduce radiation exposure to the workers.

Concrete immediately surrounding the reactor vessel is expected to be radioactive and will be removed by controlled blasting. This blasting process is well-developed, safe and is the most cost effective way to remove the heavily-reinforced concrete from the structure.

The surfaces of sections of interior floors within areas of the Reactor Building and other buildings in the power block are expected to be contaminated from exposure to contaminated air/water as a result of plant operations. This contamination will be removed by scarification (surface removal) so that the remaining surface will be clean and will not require costly controlled burial.

All contaminated process equipment, pipe hangers, supports and electrical components will be removed and disposed of by controlled burial.

Finally, an extensive radiation survey will be performed to ensure all radioactivity above the levels specified by the NRC has been removed from the site. With NRC confirmation, the facilities may be released for unrestricted access.

Period 3 - Site Restoration - This period begins once license termination activities have concluded and involves the demolition of all remaining structures, typically to a depth of three feet below grade. Clean rubble would be used on-site for fill and additional soil would be used to cover each subgrade structure.

Q. Does The Estimated Cost of Decommissioning Include An Allowance For Disposal of High-Level Radioactive Waste?

A. No. It is important to note that, although decommissioning of a site cannot be complete without the removal of all spent fuel and source material, the disposition of high-level waste is outside the scope of decommissioning. In accordance with the Nuclear Waste Policy Act of 1982 (Public Law 94-425), the DOE is required by law to enter into contracts with owners and/or generators of spent fuel, pursuant to which the DOE is contractually responsible for final disposition of spent fuel as high-level nuclear waste. To cover the cost of spent fuel disposition, the DOE assesses the facility operator 1 mill/Kwh based on net electrical generation. Therefore, the cost of disposal of spent fuel is accounted for separately and is specifically excluded from the decommissioning cost estimates.

Q. Does the Presence of Spent Fuel On-Site, Following Plant Shutdown, Affect The Decommissioning Process?

A. Yes. Although the study does not address the removal or disposal of spent fuel from the Susquehanna SES site, it does consider the constraint that the presence of spent fuel on the site can impose on other decommissioning activities. In particular, the decommissioning scheduling performed in support of the Susquehanna SES study recognizes a DOE minimum cooling prerequisite for transfer of five years. As such, this requirement for spent fuel cooling and handling systems and facilities at the plant will necessarily delay the final release of the site for alternative/unrestricted use. This delay is reflected in the increased cost of the period-dependent activities. To the extent possible, the decommissioning estimate was structured around the spent fuel area of the plant and its availability for decontamination, such that delays in decommissioning other portions of the facility could be minimized. Decommissioning would proceed on the surrounding facilities and non-essential systems during the five year transfer period.

Q. Does The Process Of Decommissioning Extend Beyond The Removal Of Contaminated and Activated Material From The Site?

A. Yes. There are additional activities, beyond the removal of contaminated material, that will be undertaken in the process of releasing the site for alternative use. This work includes costs for the remaining dismantling and grading operations.

Q. Why Is Dismantling After A Power Plant Is Taken Out Of Service The Appropriate Alternative?

A. Guarding retired power plants indefinitely is costly, requiring either a full-time guard force, or intrusion detection devices and alarms to local law enforcement agencies, and general building maintenance to maintain the structures in a safe condition. Furthermore, prompt dismantling of retired power plants makes the site available for alternative uses at the earliest possible time.

Q. Is Reuse Of The Site For A Power Plant A Potential Use?

A. Yes.

Q. If The Site Could Be Reused, Why Couldn't The Power Plant Components Be Reused In Repowering?

A. The designs of new generation power plants are not likely to use the same size and configuration of components, nor require the same type of building enclosures. Optimum facility design will be sized to match the megawatt size of a replacement power plant, if any, either larger or smaller. For example, new combustion turbine-generators are modular, self-contained units that don't need a building enclosure. Combined cycle units may require larger turbine buildings to enclose the waste heat steam generators which supply steam to the turbine. The cost to renovate older buildings and bring them to current safety code standards, combined with the less-than-optimum facility design makes reuse of the existing buildings an unlikely scenario. Furthermore, the existing components are likely to be of an obsolete design, more costly to operate and maintain and may not be compatible with new instrumentation and control systems.

Q. Please Describe The Cost Components Of Site Restoration.

A. The largest component of the site restoration costs is for dismantling the decontaminated structures. Next largest are costs incurred to remove certain non-contaminated systems and components. This work must be accomplished to provide access to all areas of the plant for the radiation surveys required by the NRC prior to license termination and release of the site for another use.

Q. Why Is It Necessary To Dismantle The Remaining Structures At The Site?

A. Efficient removal of the contaminated materials and verification that the radionuclide concentrations are below the stringent NRC limits will require substantial damage to many of the structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination work will damage power block structures including the Reactor, Radwaste and Turbine Buildings.

Verifying that subsurface radionuclide concentrations meet NRC site release requirements may require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This will be necessary for those facilities and plant areas where historical records indicate the potential of radionuclides having been present in the soil, where inventory losses have been recorded, or where required to confirm that subsurface process and drain lines did not leak over the operating life of the units.

It is also important to remember that the Susquehanna SES structures were custom designed and built to support a specific nuclear unit that went into service in the early 1980's. They would most likely be an impediment rather than a benefit to any potential future plant, if one were ever to be constructed at the site. Moreover, the facility's infrastructure degrades without continual maintenance. Unless the site is redeveloped shortly after release of its NRC license, the value in reusing plant facilities quickly diminishes. For example, following NASA's development of TVA's abandoned Yellow Creek nuclear power plant for its Advanced Solid Rocket Motor program, a Lockheed spokesman was quoted as stating: "[t]he abandoned nuclear power plant contributed little to the NASA project. Some of the power and water infrastructure was used but had to be reconstructed after eight years of neglect."

Dismantling is clearly the most appropriate and cost-effective option and should serve as the foundation for the decommissioning cost estimate. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed.

Q. Is it Possible That Future Changes In Technology And Regulation Could Affect The Dismantling Costs?

A. Yes. The TLG cost estimates prepared for these plants are based on state-of-the-art technology. No allowance was made for potential changes in technology and regulations. It is my recommendation that PP&L thoroughly review these estimates periodically and revise them, if necessary, to account for cost increases or decreases as influenced by future changes in technology and regulations. It should be noted that contingency, as used in the estimate, is restricted to cover uncertainties within the decommissioning process and is not intended as price protection.

Q. What Is The Feasibility Of The Decommissioning Premise?

A. There is extensive experience in the United States and in other countries for the complete dismantling of fossil power plants and related industrial facilities. This experience includes the dismantling of chemical refineries, steel mills, and nuclear power plants (with their associated non-nuclear turbine-generator portions). This directly related experience shows that the PP&L plants can be completely dismantled safely.

Between 1960 and 1991, 92 licensed nuclear reactors were designated for, or were in the process of being, decommissioned in the United States. Of these, thirteen were nuclear power plants, four were demonstration nuclear power plants, eight were licensed test reactors, and 49 were research reactors. The remaining 18 were critical (non-power producing) reactors and/or critical facilities decommissioned or scheduled to be decommissioned. They have been or will be totally dismantled, with their licenses terminated. Many other reactor facilities in Europe, Japan and Canada have been successfully decommissioned using demonstrated techniques. France has decommissioned 13 reactors, Germany 6, Italy 8, Japan 7, Switzerland 2, United Kingdom 5 and Canada 2.

The International Atomic Energy Agency (IAEA) indicates that 147 decommissioning programs have been undertaken or completed by its member countries. However, no breakdown is available for the various types of reactors from the IAEA.

The feasibility of decommissioning in the U.S. is well documented in the successful dismantling of Shippingport Atomic Power Station, Elk River Reactor, Walter Reed Army Research Reactor, Ames Laboratory Reactor and Sodium Reactor Experiment (SRE) Facilities. Currently decommissioning is underway at the Ft. St. Vrain 330 MWe high temperature gas-cooled reactor as well as near completion at the 819 MWe Shoreham Nuclear Plant. Pre-decommissioning activities (early component removal) are underway at the shutdown Yankee Rowe unit and in the planning stages for the 1130 MWe Trojan Nuclear Plant. Internationally, the decommissioning programs underway in England (Windscale Reactor), Germany (Gundremmingen), and Japan (Japan Power Demonstration Reactor) are further evidence of demonstrated technology. The basic activities of cutting pipe, segmenting vessels, demolishing reinforced concrete and decontaminating contaminated systems and structures are independent of the size of the structure or megawatt rating of the plant on a unit cost factor basis ($/cut, $/cubic yard, etc.).

For example, a contaminated 12-inch diameter pipe in a 3000 MWt plant takes as long to cut as it does in a 58 MWt plant, although the number of lengths of pipe to be cut will be greater in the larger plant.

The major activities include removal and burial of contaminated piping and components using conventional power hack saws, oxyacetylene torches or plasma arc torches within a contamination control tent. Removal of the reactor vessel and internals can be accomplished using an arc-gouging fuel gas torch or an arc saw which is currently capable of cutting through carbon and stainless steel up to 12 inches thick (current vessels are less than 10 inches thick).

The remote manipulator technology required to cut the reactor vessel and internals was developed by Oak Ridge National Laboratory for the Elk River Reactor dismantling. This technology uses the plasma arc torch for cutting. This same tool was used in the SRE vessel cutting activity.

Many of the tools and techniques used in decommissioning have been used in operating plants for maintenance and equipment replacement programs. Such technology, therefore, is not unique and further shows the feasibility of decommissioning.

Controlled blasting concrete demolition methods are well developed. They have been used in the mining industry, and were successfully demonstrated in the demolition of the Elk River Reactor. Heavily reinforced, eight foot thick concrete sections of the biological shield were safely removed with explosives, without damaging or interfering with the operation of adjacent operating power generating units. The successful application of these decommissioning techniques in both small and large nuclear power plants demonstrates assurance of decommissioning feasibility. Both the technology and the methodology for efficient decommissioning are available and fully tested.

Q. Does The NRC's Rule On Decommissioning, "General Requirements For Decommissioning Nuclear Facilities," As Published In The Federal Register On June 27, 1988, Have Any Effect On Your Decommissioning Cost Estimate For Susquehanna SES?

A. Yes. The rule, as published, requires licensees to assure the availability of funds by submitting a decommissioning funding plan to the NRC. PP&L has provided an initial submittal in 1990, which will be updated with the preparation of the preliminary decommissioning plan, 5 years prior to the cessation of plant operations. The rule also requires utilities to perform a periodic review of the funding plan over the life of the facility. TLG's site-specific cost estimate and decommissioning alternatives are formulated within the framework of the NRC's rule.

Q. Is It Necessary To Select A Specific Decommissioning Method At This Time?

A. No. The actual method or combination of methods selected to decommission Susquehanna SES should be based on a detailed economic, engineering and environmental evaluation of the alternatives considering the site and surroundings at the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear power facilities. However, for financial planning purposes the decommissioning cost funding should be based upon the DECON methodology.

Q. Does This Conclude Your Prepared Direct Testimony?

A. Yes.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 14

Direct Testimony of Clyde D. Beers

Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY
DIRECT TESTIMONY OF
CLYDE D. BEERS

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

A. My name is Clyde D. Beers and my business address is Centre Square East, 1500 Market Street, Philadelphia, PA 19102.

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

A. I am employed as a Principal of Towers Perrin, an actuarial and management consulting firm with over 5,000 employees which provides services to over 8,000 clients throughout the world. I am a consulting actuary and employee benefits consultant in the firm. I also manage the Philadelphia Office's total Consulting Practice. Formerly, I was head of the Employee Benefit Consulting Practice, and head of one of three multi-disciplinary units within the Philadelphia Office's Consulting Practice.

3. Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Wesleyan University with a Bachelor of Science degree in Mathematics. I am a Fellow of the Society of Actuaries, a Member of the American Academy of Actuaries and an Enrolled Actuary. As an Enrolled Actuary, I am certified by the federal government to provide actuarial valuations under the Employee Retirement Income Security Act, commonly known as ERISA. I am a consulting actuary, with over 25 years of actuarial experience. I currently serve as actuary for a number of major corporations with regard to their pension and postretirement welfare programs.

4. Q. **PLEASE DESCRIBE THE NATURE OF THE SERVICES PROVIDED BY TOWERS PERRIN TO PENNSYLVANIA POWER & LIGHT COMPANY, INC. (PP&L).**

A. Towers Perrin serves as actuary and employee benefits consultant for PP&L's qualified and non-qualified pension plans, as well as for PP&L's retiree and active employee welfare programs. In this capacity, Towers Perrin provides advice on financial and design decisions with regard to these programs, and performs periodic actuarial valuations and financial forecasts. Towers Perrin has also provided employee communication and compensation consulting services to PP&L.

5. Q. **MR. BEERS, PLEASE DESCRIBE THE NATURE OF THE SERVICES YOU PROVIDE TO PP&L.**

A. I serve as a consulting actuary and employee benefits consultant. I am the Enrolled Actuary for PP&L's qualified pension plan, the actuary for PP&L's non-qualified pension plans and I am one of two actuaries who provide services on retiree welfare valuations and other related projects.

6\. Q. **PLEASE DESCRIBE THE ROLE OF AN ACTUARY WHO PERFORMS VALUATIONS REGARDING POSTRETIREMENT EMPLOYEE BENEFITS PLANS.**

A. An actuary who works with postretirement employee benefit plans, such as a pension or welfare benefits plan, provides financial evaluations of future events using specialized mathematical and analytical skills. Actuaries calculate the actuarial present value of future retiree/dependents benefits (such as pensions, postretirement health care and life insurance) based on the probability of the occurrence of those events that impact the payment of the benefit. Actuarial calculations are dependent upon a variety of assumptions to project whether the employee will remain in active service to the point at which benefit eligibility is attained, the year-by-year cost of providing the benefit while it remains in force, the duration over which the benefit will continue and the discount rate (or rates) used to reflect the time value of money. Other contingencies are also reflected, such as spouse's benefits, spouse's death benefits, etc. For ERISA/DEFRA (Deficit Reduction Act) funding purposes, actuarial assumptions are to reflect the actuary's best estimate of future events, while for financial accounting purposes, actuarial assumptions are to reflect the employer's best estimate.

Actuarial calculations also require the use of actuarial cost, or attribution, methods for allocating the actuarial present value of benefit costs to specific time periods.

The actuary analyzes the valuation results in order to provide a company with information regarding the appropriate level of expense to recognize during an accounting period, the appropriate level of current funding, and the long-term financial implications of the commitments. In addition, an actuary who works with pension plans or postretirement welfare plans, such as PP&L's, utilizes actuarial expertise to analyze recent experience and current trends in order to anticipate future economic and demographic experience related to the valuation of the plans' obligations.

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

A. The purpose of my pre-filed direct testimony is to comment on behalf of the Company with regard to its claims for postretirement benefits other than pensions (OPEBs) determined under Statement of Financial Accounting Standards No. 106 (SFAS 106). In the case of PP&L, OPEBs consist primarily of medical and life insurance coverage for retirees and their dependents.

8. Q. **WHAT PP&L OPEBS ARE VALUED BY TOWERS PERRIN AND ARE THE SUBJECT OF THIS TESTIMONY?**

A. Based upon our discussions with PP&L, we provide an annual actuarial valuation for PP&L's postretirement medical and life insurance benefits (Retiree Welfare Plans), which are subject to both accrual accounting standards under SFAS 106 and DEFRA funding limits. PP&L expects to fund its Retiree Welfare Plans at a level equal to its SFAS 106 cost, subject to DEFRA funding limits. The SFAS 106 accounting standard provides guidance for the determination of the OPEB Plans' annual accounting cost, which specifies that the cost of OPEBs be expensed over the service period of employees. DEFRA provides guidance in regard to the tax-deductible funding limit for the PP&L Voluntary Employee Benefit Association (VEBA) trusts. PP&L has separate VEBA trusts for its union and non-union employees.

9. Q. **WHAT ARE THE SPECIFIC RESULTS FOR THE RETIREE WELFARE PLANS VALUED BY TOWERS PERRIN?**

A. Towers Perrin has been requested to provide a determination of the SFAS 106 cost and the tax-deductible funding limit for the Retiree Welfare Plans in regard to PP&L's 1995 fiscal year. The 1995 Actuarial Report for the Retiree Welfare Plans, identified as Exhibit CDB-1, provides Towers Perrin's SFAS 106 results. PP&L's SFAS 106 cost for

1995 has been determined to be $25,856,836. DEFRA funding results for 1995 indicate that PP&L will be able to contribute its SFAS 106 cost to its VEBA trusts and receive a current-year tax deduction for the entire contribution.

10. Q. **MR. BEERS, WOULD YOU PLEASE SUMMARIZE PP&L's OPEB PROVISIONS?**

A. These plans are considered health and welfare plans. A written summary of the Plans' provisions is included in the actuarial report (Exhibit CDB-1).

11. Q. **HOW DO PP&L'S EMPLOYEE BENEFITS COMPARE TO THOSE PROVIDED BY OTHER EMPLOYERS?**

A. Towers Perrin maintains an extensive database which allows us to compare the types of benefits provided by different companies. Based on that review, I conclude that PP&L's Employee Benefits are consistent with utility practice.

12. Q. **MR. BEERS, WOULD YOU PLEASE SUMMARIZE THE ACTUARIAL METHODS AND ASSUMPTIONS THAT WERE USED TO PERFORM THE ANNUAL PP&L VALUATION OF THE RETIREE WELFARE PLANS AS OF JANUARY 1, 1995?**

A. A detailed, written summary of this information is included in the actuarial report attached as Exhibit CDB-1. In particular, the actuarial assumptions are summarized on pages SI-12 to SI-15.

13. Q. **WHAT ARE THE MAJOR CATEGORIES OF ASSUMPTIONS FOR ACTUARIAL VALUATION PURPOSES?**

A. There are two major categories: economic assumptions and demographic assumptions.

Key economic assumptions for OPEB purposes include the discount rate, long-term rate of return on assets and health care cost trend rate.

Key demographic assumptions are the expected retirement age pattern, mortality rates and termination rates.

14. Q. **HOW ARE THESE ASSUMPTIONS SELECTED?**

A. A review of past experience, including both the Company's experience and broader experience, is first made where available. Recent trends are also reviewed. The actuary then discusses with the Company their joint expectations for the future. This process is typically followed with respect to each key assumption.

In regard to economic assumptions, current expectations of near-term and long-term inflation are typically chosen first. When choosing economic assumptions unique to retiree welfare valuations, such as the health care cost trend rate, differences between current medical inflation and general price inflation as well as emerging trends and future expectations must also be taken into account.

With regard to demographic assumptions, near-term historical data is typically reviewed first. Then, a review must be made of the circumstances underlying this data. For example, if a company has experienced layoffs, early retirement window programs, acquisitions or divestitures during the data collection period, this could make the recent experience less predictive. The credibility of the company's data must also be considered. For example, company-based termination rates and retirement rates are typically used, while disability and mortality rates are usually based upon broader experience (standard actuarial tables). For PP&L, key demographic elements are monitored by Towers Perrin annually and reflected in the final choice of valuation assumptions. Finally, Towers Perrin and PP&L agree upon a reasonable assumption package which reflects this past experience and both parties' expectations for the future.

15. Q. **PLEASE DESCRIBE HOW THE SFAS 106 DISCOUNT RATE OF 7.5% AS WELL AS THE PRE-TAX LONG-TERM RATE OF RETURN ON ASSETS AND INTEREST RATE OF 6.50% ASSUMPTIONS WERE SELECTED?**

A. SFAS 106 specifies that the choice of discount rate for benefit obligations should reflect high-quality bond yields and settlement rates as of the measurement date. Experience under SFAS 106 indicates that companies look to a range of long-term rates in selecting a discount rate. The Securities and Exchange Commission (SEC) recently released a statement indicating that a bond yield reflecting Moody's AA or higher-quality bonds is required for purposes of selecting a discount rate. As of October 1, 1994, high-quality bond yields and settlement yields can be summarized as follows:

- Moody's AA bonds 8.6%
- Moody's AAA bonds 8.5%
- 30-year U.S. treasuries 7.7%
- PBGC immediate rates 6.0%

Settlement of fixed commitments in today's market is likely to be at rates close to but somewhat below long-term U.S. treasuries. The selection of a 7.5% discount for SFAS 106 cost purposes was chosen accordingly. The actual discount rate used as of January 1, 1995 and future years may differ from 7.5% if interest rates move substantially. The choice of the long-term rate of return on assets assumption and the interest rate for funding purposes is based on the expected future earnings rate on plan assets. PP&L's VEBA trusts are currently invested in intermediate duration bonds. The expected return on intermediate bonds is linked to current and expected inflation. The CPI increased during 1993 only 2.7%. Thus, PP&L, in consultation with Towers Perrin, selected a rate of return on assets assumption for funding purposes of 6.50%.

16. Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE PP&L VALUATION ASSUMPTIONS FOR 1995?

A. Overall, the assumptions used for these valuations are internally consistent and reasonable. They are also consistent with plan investment policies in place at the present time.

17. Q. ARE THESE ASSUMPTIONS REASONABLE FOR PP&L?

A. Yes.

18. Q. PLEASE SUMMARIZE THE RESULTS OF YOUR SFAS 106 VALUATION FOR 1995?

A. A summary of the results of our valuation is set forth in Exhibit CDB-1. The 1995 OPEB cost under SFAS 106 for PP&L is $20,295,876 for the medical plan, and $5,560,960 for the life insurance plan, for a total of

$25,856,836. These costs are based on an election by PP&L to amortize the Transition Obligation, calculated as of January 1, 1993, over 20 years, the maximum time period allowable under SFAS 106. Projected benefit payments ("pay-as-you-go" benefit payments) for PP&L in 1995 are expected to be $12,441,680. Therefore, if PP&L contributes $25.9 million and pays out $12.4 million, then $13.5 million will accumulate to fund future benefits for current and future PP&L retirees. Investment earnings on those assets will reduce future PP&L expense.

19. Q. **DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.