BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061398

PPL Gas Utilities Corporation

Statement No. 6

9/9/04 JCS

Direct Testimony of Paul R. Moul

DOCUMENT FOLDER  Docketed OCT 05 2006
## Glossary of Acronyms and Defined Terms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Defined Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFUDC</td>
<td>Allowance for Funds Used During Construction</td>
</tr>
<tr>
<td>β</td>
<td>Beta</td>
</tr>
<tr>
<td>b</td>
<td>Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends</td>
</tr>
<tr>
<td>bxr</td>
<td>Represents internal growth</td>
</tr>
<tr>
<td>CAPM</td>
<td>Capital Asset Pricing Model</td>
</tr>
<tr>
<td>CCR</td>
<td>Corporate Credit Rating</td>
</tr>
<tr>
<td>CE</td>
<td>Comparable Earnings</td>
</tr>
<tr>
<td>DCF</td>
<td>Discounted Cash Flow</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>FOMC</td>
<td>Federal Open Market Committee</td>
</tr>
<tr>
<td>g</td>
<td>Growth rate</td>
</tr>
<tr>
<td>GAAP</td>
<td>Generally accepted accounting principles</td>
</tr>
<tr>
<td>GCR</td>
<td>Gas Cost Rate</td>
</tr>
<tr>
<td>GDP</td>
<td>Gross Domestic Product</td>
</tr>
<tr>
<td>IGF</td>
<td>Internally Generated Funds</td>
</tr>
<tr>
<td>LDC</td>
<td>local distribution companies</td>
</tr>
<tr>
<td>Lev</td>
<td>Leverage modification</td>
</tr>
<tr>
<td>LIBOR</td>
<td>London Interbank Offered Rate</td>
</tr>
<tr>
<td>LT</td>
<td>Long Term</td>
</tr>
<tr>
<td>MM</td>
<td>Modigliani &amp; Miller</td>
</tr>
<tr>
<td>MLP</td>
<td>Master Limited Partnerships</td>
</tr>
<tr>
<td>MPL</td>
<td>Minimum Pension Liability</td>
</tr>
<tr>
<td>NAIC</td>
<td>National Association of Insurance Commissioners</td>
</tr>
<tr>
<td>OCI</td>
<td>Other Comprehensive Income</td>
</tr>
<tr>
<td>PPUC</td>
<td>Pennsylvania Public Utility Commission</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utility Commission</td>
</tr>
<tr>
<td>PUCH</td>
<td>Public Utility Holding Company</td>
</tr>
<tr>
<td>r</td>
<td>represents the expected rate of return on common equity</td>
</tr>
<tr>
<td>ACRONYM</td>
<td>DEFINED TERM</td>
</tr>
<tr>
<td>---------</td>
<td>--------------</td>
</tr>
<tr>
<td>Rf</td>
<td>Risk-free rate of return</td>
</tr>
<tr>
<td>Rm</td>
<td>Return on the market</td>
</tr>
<tr>
<td>RP</td>
<td>Risk Premium</td>
</tr>
<tr>
<td>s</td>
<td>Represents the new common shares expected to be issued by a firm</td>
</tr>
<tr>
<td>s x v</td>
<td>Represents external growth</td>
</tr>
<tr>
<td>S&amp;P</td>
<td>Standard &amp; Poor’s</td>
</tr>
<tr>
<td>v</td>
<td>Represents the value that accrues to existing shareholders from selling stock at a price different from book value</td>
</tr>
<tr>
<td>ytm</td>
<td>Yield to maturity</td>
</tr>
</tbody>
</table>
Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory 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 rate of return that the Pennsylvania Public Utility Commission ("PPUC" or the "Commission") should allow PPL Gas Utilities Corporation ("PPL Gas" or the "Company"), an opportunity to earn on its rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data contained in Exhibit No. PRM-1, which is a multi-page document divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

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

A. My conclusion is that the Company's cost of common equity is within the range of 11.25% to 11.75%. From this range, the Company has proposed an 11.75% cost of equity. The Company's proposed rate of return on common is at the top of the
range, comprised of the midpoint of the range (i.e., 11.50%) plus twenty-five basis points (i.e., 0.25%), in recognition of the exemplary performance of the Company’s management. With this return, I have presented on Schedule 1 the weighted average cost of capital, which is 9.35% for PPL Gas. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company’s cost of capital?

A. The Company provides natural gas service to approximately 76,000 customers in over half of the counties throughout Pennsylvania. In 2004, the Company’s gas throughput (to both sales and transportation customers) was comprised of approximately 28% to residential customers, 29% to commercial customers, and 43% to industrial customers. Overall, the Company’s throughput is represented by 42% to heating customers, 3% to other gas sales customers, and 54% to transportation customers. Industrial sales are concentrated in 327 customers, of which 220 are sales customers and 107 are transportation customers. This sales profile signifies a high risk for the Company.

The Company obtains its natural gas from Southwest and Appalachian suppliers with delivery arrangements with interstate pipelines. The Company supplements its flowing natural gas with gas withdrawn from underground storage. PPL Gas was formerly known as Penn Fuel Gas, Inc. and was the parent company
Q. How have you determined the cost of common equity in this case?
A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as PPL Gas. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's cost of common equity is within the range of 11.25% to 11.75%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?
A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality. I have explained the basis of these ratesetting principles in Appendix B.

Q. What factors have you considered in measuring the cost of equity in this case?
A. The models that I used to measure the cost of common equity for the Company
were applied with market and financial data developed from my proxy group of nine natural gas companies. The proxy group consists of natural gas companies that are included in The Value Line Investment Survey. They have operations in the New England, Middle Atlantic, South Atlantic, North Central and South Central regions of the U.S., their stock is traded on the New York Stock Exchange, they have not cut or omitted their dividend since 2000, and they are not currently the target of a merger, acquisition, or self-induced sale. The companies in the gas proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the “Gas Group” throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not separately measured the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies’ analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity.
depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

<table>
<thead>
<tr>
<th>Gas Group</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>DCF</td>
<td>10.40%</td>
</tr>
<tr>
<td>RP</td>
<td>11.50%</td>
</tr>
<tr>
<td>CAPM</td>
<td>12.49%</td>
</tr>
<tr>
<td>Comparable Earnings</td>
<td>14.45%</td>
</tr>
<tr>
<td>Average</td>
<td>12.21%</td>
</tr>
<tr>
<td>Median</td>
<td>12.00%</td>
</tr>
<tr>
<td>Mid-point</td>
<td>12.43%</td>
</tr>
</tbody>
</table>

From these measures of the cost of equity, the average and the median values are 12.21% and 12.00%, respectively. From the results derived from the market models of the cost of equity (i.e., DCF, Risk Premium and CAPM), the average return is 11.46%. For this case, I recommend that the Company’s rate of return on common equity be set within the range of 11.25% to 11.75%. In order to provide recognition of the exemplary performance of the Company’s management, the rate of return on common equity proposed in the case is at the top of the range.

The exemplary performance of the Company’s management is described in the testimony of Mr. Charles C. Rogala. Mr. Rogala explains the many initiatives that the Company has undertaken, which have produced high quality service. In particular, Mr. Rogala has shown that the Company ranks high in customer service.
In recognition of its outstanding performance and its goal of maintaining reasonably priced rates, the Company should be granted an opportunity to earn an 11.75% rate of return on common equity.

I should further note that at this time, the DCF model is providing atypical results. That is to say, the low DCF returns can be traced in part to the unfavorable investor sentiment for the gas companies. Indeed, the average Value Line Timeliness Rank for my Gas Group is "4," which places them in the below average category and signifies that they are relatively unattractive investments. Moreover, page 5 of Schedule 12 shows that the natural gas distribution companies are ranked 92 out of 98 industries for probable performance over the next twelve months. The significance of these low rankings is that performance for this group is expected to be subpar, thereby indicating that the DCF results will not provide a cost of equity indication that corresponds with the results of the other methods/models. As such, I am recommending less reliance on DCF in this case. That is not to say that I have ignored the DCF results, but rather I believe that my recommended range of 11.25% to 11.75% is an appropriate estimate of the Company's cost of common equity and is reasonable given the range of cost estimates produced by the other three methods (i.e., 11.50%, 12.31% and 14.45%). I also believe my recommended cost of equity range of 11.25% to 11.75% is appropriate because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events that could occur during the rate effective period. Therefore, a return on common equity of within the range of 11.25% to 11.75% is appropriate and reasonable in this case.
Q. What factors currently affect the business risk of the natural gas utilities?
A. The new competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in commodity prices has had a negative impact on its customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCR mechanism. Higher and volatile gas costs may result in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. The resulting high gas prices have also had an impact on the number of delinquent customer accounts.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. Does the Company face competition in its natural gas business?
A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors
through bypass facilities and placed more responsibilities on local distribution companies, such as PPL Gas, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

Q. How does the Company's throughput to industrial and transportation customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial and transportation customers. The threat of bypass is a common characteristic of large volume users. The throughput to the Company's top ten customers represented 6,217,901 Dth, or approximately 25% of total throughput.

Large volume users that have traditionally used transportation service also have the ability to bypass the Company's system. This situation is exemplified by former customers (Pittsburgh - Corning and Ball Foster) which previously bypassed the Company's facilities. Another former customer (Rocktenn) purchased the Company's facilities in order to initiate bypass. It has become necessary for the Company to flex its rates in order to retain other customers on their system. Bypass and the threat of bypass have been chronic problems for the Company. In this regard, the status of actual bypass and volumes at risk are shown below:
DIRECT TESTIMONY OF PAUL R. MOUL

<table>
<thead>
<tr>
<th>Customer Name</th>
<th>Bypass Status</th>
<th>Volumes Lost</th>
<th>Volumes At-Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>St. Gobain Containers</td>
<td>In Place</td>
<td>1,003,750</td>
<td></td>
</tr>
<tr>
<td>Pittsburgh Corning</td>
<td>In Place</td>
<td>321,732</td>
<td>35,748</td>
</tr>
<tr>
<td>International Waxes</td>
<td>In Place</td>
<td>144,000</td>
<td>59,250</td>
</tr>
<tr>
<td>Jersey Shore Steel</td>
<td>In Place</td>
<td>88,660</td>
<td>44,330</td>
</tr>
<tr>
<td>Osram Sylvania</td>
<td>Viable Threat</td>
<td>-</td>
<td>616,377</td>
</tr>
<tr>
<td>Glen Gery - Bigler</td>
<td>Viable Threat</td>
<td>-</td>
<td>268,267</td>
</tr>
<tr>
<td>Herr Foods</td>
<td>Viable Threat</td>
<td>-</td>
<td>244,891</td>
</tr>
<tr>
<td>JLG - McConnellsburg</td>
<td>Viable Threat</td>
<td>-</td>
<td>153,585</td>
</tr>
<tr>
<td>SCI Forest</td>
<td>Viable Threat</td>
<td>-</td>
<td>88,597</td>
</tr>
</tbody>
</table>

Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from the competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on its operations from facilities located outside the Company's service territory.

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

A. Yes. Many of the Company's residential customers use natural gas for space heating purposes. This indicates that a significant proportion (i.e., 38%) of the Company's residential and commercial customers present a low load factor profile and that their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. For these sales, the Company's revenues are subject to variations caused by weather abnormalities.

Q. Please indicate how its construction program affects the Company's risk profile.
A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The Company projects its construction expenditures will be:

<table>
<thead>
<tr>
<th>Year</th>
<th>Expenditures ($000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>14,430</td>
</tr>
<tr>
<td>2007</td>
<td>15,005</td>
</tr>
<tr>
<td>2008</td>
<td>15,082</td>
</tr>
<tr>
<td>2009</td>
<td>14,166</td>
</tr>
<tr>
<td>2010</td>
<td>14,184</td>
</tr>
<tr>
<td>Total</td>
<td>72,867</td>
</tr>
</tbody>
</table>

Over the next five years, these capital expenditures will represent an approximate 37% ($72,867,000 ÷ $199,275,000) increase in utility plant in service (net of depreciation) from the amount at December 31, 2005.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular PPL Gas?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility’s cost of equity?
Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I compared PPL Gas to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

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

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What criteria did you employ to assemble the Gas Group?

A. The Gas Group that I employed in this case includes companies that (i) are engaged in similar business lines, (ii) have publicly-traded common stock that is listed on the New York Stock Exchange, (iii) are contained in The Value Line Investment Survey in the industry group entitled "Natural Gas Distribution," (iv) have operations in the New England, Middle Atlantic, South Atlantic, North Central and South Central regions of the U.S., (v) have not cut or omitted their dividend since 2000, (vi), are not currently the target of a merger or acquisition, and (vii) have at least 70% of their assets represented by gas operations.

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 important 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 shown directly 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 compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for PPL Gas, the Gas Group, and the S&P Public Utilities?

A. There is no public rating on the debt of PPL Gas. The long-term debt that was originally issued by North Penn Gas Company carries a designation of “2” from the National Association of Insurance Commissioners (“NAIC”), which is at the bottom of the investment grade credit quality categories that would correspond with the BBB/Baa bond rating. It is important, therefore, that the Company experience an opportunity to achieve an adequate rate of return so that its credit quality conforms with the standards for stronger (i.e., A) credit quality by Standard & Poor’s Corporation (“S&P”) and Moody’s Investors Service (“Moody’s”) -- both national recognized credit rating agencies. Presently, the average corporate credit rating (“CCR”) for the Gas Group is A from S&P and the Long Term (“LT”) issuer rating is A3 from Moody’s. The CCR designation by S&P and LT issuer rating by Moody’s focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is BBB by S&P and Baa2 by Moody’s. Many of the financial indicators that
DIRECT TESTIMONY OF PAUL R. MOUL

I will subsequently discuss arc considered during the rating process.

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

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2000-2004. Prior to 2003, there are no financial statements available for PPL Gas as it exists today. For earlier years, I combined the balance sheets and income statements for PFG Gas, Inc. (excluding Maryland) and North Penn Gas Company for my historical analysis. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, PPL Gas is much smaller than the average size of the Gas Group. The average size of the S&P Public Utilities is much larger than the Gas Group, and the Gas Group is much larger than PPL Gas. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for PPL Gas compared to the Gas Group, and the Gas Group compared to the S&P Public Utilities.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.
There are no market ratios available for PPL Gas because the Company's stock is owned by PPL Corporation. The five-year average price-earnings multiple for the Gas Group was similar to that of the S&P Public Utilities. The five-year average dividend yield was somewhat higher for the Gas Group, as compared to the S&P Public Utilities. The average market-to-book ratio was somewhat higher for the Gas Group than the S&P Public Utilities.

**Common Equity Ratio.** The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. 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 lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 90.2% for PPL Gas, 51.9% for the Gas Group, and 37.9% for the S&P Public Utilities. The historical indicators of financial risk are not meaningful for the combined results of PFG Gas, Inc. and North Penn Gas Company because much of its debt was issued by Penn Fuel Gas, Inc. for the benefit of PFG Gas, Inc. (North Penn had issued its own debt in the past.).

**Return on Book Equity.** Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater 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 coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.344 (3.1% ÷ 9.0%) for
PPL Gas, 0.082 (1.0% ÷ 12.2%) for the Gas Group, and 0.283 (2.8% ÷ 9.9%) for the S&P Public Utilities. The earnings variability for PPL Gas was considerably higher than that of the Gas Group, thereby indicating higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income taxes). 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. The five-year average operating ratios were 84.8% for PPL Gas, 88.7% for the Gas Group, and 84.8% for the S&P Public Utilities. The operating risk for PPL Gas is fairly similar to that of the Gas Group.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) 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 interest coverage (excluding Allowance for Funds Used During Construction (“AFUDC”)) was 4.51 times for PPL Gas, 3.83 times for the Gas Group, and 2.56 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are 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 because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for PPL Gas, PPL Gas, the Gas Group, and the S&P
DIRECT TESTIMONY OF PAUL R. MOUL

Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historical cash flow statements are not available for PPL Gas so IGF cannot be calculated. Historically, the five-year average percentage of IGF to capital expenditures was 93.9% for the Gas Group, and 107.1% for the S&P Public Utilities. The IGF percentage for Gas Group was weaker than for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .82 as the average for the Gas Group (see page 2 of Schedule 3), and 1.01 as the average for the S&P Public Utilities (see page 3 of Schedule 4). Keeping in mind that the utility industry has changed dramatically during the past five years, the systematic risk percentage is 81% (.82 ÷ 1.01) for the Gas Group, using the S&P Public Utilities' average beta as a benchmark.

Q. Please summarize your risk evaluation of the Company and the Gas Group.

A. The risk of PPL Gas parallels that of the Gas Group in certain respects with regard to historical financial performance. However, PPL Gas has somewhat lower credit quality as indicated by the "2" designation in the NAIC classification. Also, the
Company’s small size adds to its risk and its earnings have been highly variable. Further, based on the Company’s business risk characteristics, especially with regard to the threat of bypass from the interstate pipelines and its relatively high percentage of throughput to industrial and transportation customers, the Company’s overall risk is above that of the Gas Group. As such, the cost of equity derived from the Gas Group would tend to understate the Company’s cost of equity.

**CAPITAL STRUCTURE RATIOS**

Q. Please explain the selection of capital structure ratios for PPL Gas.

A. It is appropriate that PPL Gas’s capital structure ratios be employed for rate of return purposes. Furthermore, consistency requires that the embedded cost rate of the Company’s senior securities also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in prior rate cases for PFG Gas, Inc. and North Penn Gas Company.

Q. Does Schedule 5 provide the Company’s capitalization and capital structure ratios?

A. Yes. Schedule 5 presents the Company’s capitalization and related capital structure ratios based upon investor-provided capital. The December 31, 2005 capitalization corresponds with the end of the historic test year in this case.

The December 31, 2006 capitalization is estimated at the end of the future test year. No new long-term debt is expected to be issued in the future test year. There is a forecast increase in the Company’s retained earnings. Also reflected on Schedule 5 are several ratesetting adjustments to the capital structure. The first adjustment is related to the call premiums on the early redemption of high cost
long-term debt. The second adjustment relates to accumulated Other
Comprehensive Income ("OCI"). Accumulated Other Comprehensive Income
("OCI") has been excluded from the Company's common equity account.

Q. Please describe the first adjustment.

A. I have adjusted the principal amount of long-term debt to exclude the amounts used
to finance premiums on the early redemption of long-term debt. To do otherwise
would deny PPL Gas 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
that was necessary to finance these transactions, and therefore an adjustment is
required to provide the return necessary to service the additional capital. Hence,
PPL Gas's long-term debt 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
PPL Gas recovers all costs incurred in providing these benefits to the customers.
To accomplish these savings, the Company paid the debt holders a premium for
surrendering its securities prior to maturity. These premiums represented an
investment made by PPL Gas to reduce its overall cost of capital. Since the reduced
interest costs 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. Please explain the second adjustment.

A. It is critical that the accumulated OCI be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base of the Company (i.e., they do not generate or consume any cash). A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. As such, MPL arises from a decline in stock market values and a decline in interest rates, which reduces the value of the trust fund assets and increases the present value calculation of the pension benefit obligation. SFAS 87 requires that the MPL be recognized as a pension expense over future periods, as long as the MPL continues to exist. If the stock market improves and when interest rates rise from recent low levels, the MPL will reverse and not impact future pension expense. Hence, the accumulated OCI must be excluded from the common equity.

Q. Does Schedule 5 show the Company's short-term debt outstanding?

A. Yes. An average balance of short-term debt has been used for the purpose of this schedule. The Commission has traditionally considered an average balance of
short-term debt for gas distribution utilities. This practice has been followed in
order to accommodate the seasonal nature of short-term borrowings.

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

A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect
known or reasonably foreseeable changes which will occur during the course of the
future test year, as well as those that are known to occur shortly thereafter. As a
result, I will adopt the Company's future test year-end capital structure ratios of
44.32% debt and 55.68% common equity. These capital structure ratios are the best
approximation of the mix of capital the Company will employ to finance its rate
base during the period new rates are in effect.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of PPL Gas's capital
structure?

A. Consistency with the capital structure ratios for the Company requires that the
embedded cost rates of PPL Gas's senior securities must also be employed. This
procedure is consistent with the ratesetting procedures used by the Commission in
prior rate cases for PFG Gas, Inc. and North Penn Gas Company. The
determination of the cost of debt 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 6, the
actual embedded cost rate of long-term debt was 6.94% on December 31, 2005. By
December 31, 2006, the embedded debt cost rate is estimated to be 6.30%, as
shown on page 3 of Schedule 6. The details leading to the development of the
individual effective cost rates for each series of long-term debt, using the cost rate
to maturity technique, are shown on page 3 of Schedule 6. The cost rate, or yield to
maturity ("ytm"), is the rate of discount that equates the present value of all future
interest and principal payments with the net proceeds of the bond.

For the future test year, the interest cost on the Company’s short-term debt
has been projected based upon the implied forward three-month Labor InterBank
Offered Rate ("LIBOR") as provided by Bloomberg. To the LIBOR forecast rate, a
margin has been added to reflect the Company’s short-term borrowing rate.

I will adopt the 6.35% prospective embedded cost of debt for rate of return
purposes. The 6.35% debt cost rate is related to the amount of long-term debt
shown on Schedule 5 which provides the basis for the 44.32% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for
PPL Gas.

A. Although my fundamental financial analysis provides the required framework to
establish the risk relationships among PPL Gas, the Gas Group, and the S&P Public
Utilities, the cost of equity must be measured by standard financial models that I
describe in Appendix D. Differences in risk traits, such as size, business
diversification, geographical diversity, regulatory policy, financial leverage, and
bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of
equity can be applied in an isolated manner. 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. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and determined that the cost of equity is within the range of 11.25% to 11.75%. From this range, the Company has proposed an 11.75% return.

DISCOUNTED CASH FLOW ANALYSIS

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 E. I will summarize them here. The 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 that 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 method when applied in 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 that 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 E, the DCF approach has other limitations that
diminish its usefulness in the ratesetting process when the market capitalization
diverges significantly from book value capitalization. When this situation exists,
the DCF method will lead to a misspecified cost of equity when it is applied to a
book value capital structure.

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
book value, the resulting earnings will not produce the level of required return
specified by the model when market prices vary from book value. This is to say,
such distortions tend to produce DCF results that understate the cost of equity to the
regulated firm when using book values. This shortcoming of the DCF has
persuaded the Commission to adjust the cost of equity upward to make the return
consistent with the book value capital structure. The PPUC in its Order entered
December 22, 2004 involving PPL Electric Utilities Corporation at Docket No. R-
00049255 acknowledged that an adjustment to the DCF results was required to
make the return consistent with the book value capital structure. In that decision,
the Commission provided PPL (a wires-only electric delivery utility) with an
additional 45 basis points to the simple DCF derived cost of equity for the financial
risk difference related to the divergence of the market capitalization from the book
value capitalization. Similar provisions were made by the PPUC in its decisions
R-00016339, dated August 1, 2002 for Philadelphia Suburban Water Company in
Company at Docket No. R-00038304 (affirmed by the Commonwealth Court on
February 8, 2004), and dated August 5, 2004 for Aqua Pennsylvania, Inc. at Docket
No. R-00038805. It must be recognized that in order to make the DCF results
relevant to the capitalization measured at book value (as is done for rate setting
purposes), the market-derived cost rate cannot be used without modification. As I
will explain later in my testimony, the DCF model can be modified to account for
differences in risk attributed to changes in financial leverage when market prices
and book values diverge.

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. For the twelve months ended February 2006,
the monthly dividend yields of the Gas Group are shown graphically on Schedule 7.
The monthly dividend yields shown on Schedule 7 reflect an adjustment to the
month-end prices to reflect the build up of the dividend in the price that has
occurred since the last ex-dividend date (i.e., the date by which a shareholder must
own the shares to be entitled to the dividend payment – usually about two to three
weeks prior to the actual payment). An explanation of this adjustment is provided
in Appendix E.

For the twelve months ending February 2006, the average dividend yield
was 4.15% for the Gas 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 4.27% and 4.30%, respectively, for the Gas Group. I have used, for the purpose of my direct testimony, a dividend yield of 4.27% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields. While my use of a six-month average dividend yield is consistent with previous testimony, dividend yields have been quite volatile during the latter six-month period, rising from 3.97% in September 2005 to 4.40% in December 2005 and then declining to 4.24% in February 2006. This demonstrates the instability that is present in the DCF method, which can provide a less reliable measure of the cost of equity.

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. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix E. That adjusted dividend yield is 4.39% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). As I explain in Appendix E,
future earnings per share growth represents its primary focus because under the
constant price-earnings multiple assumption of the DCF model, the price per share
of stock will grow at the same rate as earnings per share. In conducting a growth
rate analysis, a wide variety of variables can be considered when reaching a
consensus of prospective growth. The variables that can be considered include:
earnings, dividends, book value, and cash flow stated on a per share basis.

Historical values for these variables can be considered, as well as analysts' forecasts
that are widely available to investors. A fundamental growth rate analysis can also
be formulated, which consists of internal growth ("b x r"), where "r" represents the
expected rate of return on common equity and "b" is the retention rate that consists
of the fraction of earnings that are not paid out as dividends. The internal growth
rate can be modified to account for sales of new common stock -- this is called
external growth ("s x v"), where "s" represents the new common shares expected to
be issued by a firm and "v" represents the value that accrues to existing
shareholders from selling stock at a price different from book value. Fundamental
growth, which combines internal and external growth, provides an explanation of
the factors that cause book value per share to grow over time. Hence, a
fundamental growth rate analysis is duplicative of expected book value per share
growth.

Growth can also be expressed in multiple stages. This expression of growth
consists of an initial "growth" stage where a firm enjoys rapidly expanding markets,
high profit margins, and abnormally high growth in earnings per share. Thereafter,
a firm enters a "transition" stage where fewer technological advances and increased
product saturation begins to reduce the growth rate and profit margins come under pressure. During the “transition” phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or “steady-state” stage is reached when a firm’s earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third “steady-state” growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

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

A. Although some DCF proponents would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables employed within the confines of fundamental growth described above), 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 model using the accounting values necessary to calculate fundamental growth. 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 dividend yield requirements. I follow an approach that is not rigidly formatted, because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my
opinion, all relevant growth rate indicators must be evaluated using a variety of techniques, when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, and high cost of gas are resolved in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by changes in operating expenses and capital costs.
At present, there is a bearish sentiment for the industry that has arisen from uncertain regulatory policies, and significant cost pressures, especially in the area of employee costs (i.e., pension and health care benefits), insurance costs, and the high cost of gas. The dilutive impact of recent sales of new common stock has also had a negative affect on the earnings prospects of gas utilities.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in "The Wall Street Journal," "The New York Times," "Fortune," "Forbes," and "Business Week." Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the March 10, 2006 issue of Blue Chip, those forecasts are:
DIRECT TESTIMONY OF PAUL R. MOUL

Blue Chip Economic Indicators

<table>
<thead>
<tr>
<th>Year</th>
<th>Nominal GDP</th>
<th>Corporate Profits, Pretax</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>5.3%</td>
<td>3.9%</td>
</tr>
<tr>
<td>2009</td>
<td>5.3%</td>
<td>4.6%</td>
</tr>
<tr>
<td>2010</td>
<td>5.2%</td>
<td>4.3%</td>
</tr>
<tr>
<td>2011</td>
<td>5.1%</td>
<td>5.1%</td>
</tr>
<tr>
<td>2012</td>
<td>5.2%</td>
<td>6.0%</td>
</tr>
<tr>
<td>Averages</td>
<td>5.2%</td>
<td>4.8%</td>
</tr>
<tr>
<td>2007-11</td>
<td>5.2%</td>
<td>4.8%</td>
</tr>
<tr>
<td>2012-16</td>
<td>5.2%</td>
<td>5.7%</td>
</tr>
</tbody>
</table>

These forecasts show that the rate of growth in corporate profits will decelerate during the early part of the forecast period due to the run-up in interest rates that I will discuss later in my testimony. Subsequently, growth will accelerate later in the period. It is also indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.¹

Q. What data have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. The bar graph provided on Schedule 8 shows the historical growth rates covering 5-year and 10-year periods in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical earnings per share growth rates were 6.22% and 4.78% for the Gas Group.

Schedule 9 provides projected earnings per share growth rates taken from

¹ Obviously, growth in corporate profits is negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since the 1934.
DIRECT TESTIMONY OF PAUL R. MOUL

analysts' forecasts compiled by IBES/First Call, Zacks, Reuters/MarketGuide, and
from the Value Line publication. The forecasts are generally based upon analysts'
projections for a 5-year period. IBES/First Call, Zacks, and Reuters/MarketGuide
represent reliable authorities of projected growth upon which investors rely.
Thomson Financial has acquired the entity that published the IBES consensus
forecasts, and Reuters/MarketGuide is the entity that provides the Multex data. The
IBES/First Call, Zacks, and Reuters/MarketGuide forecasts are limited 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 9 for the Gas Group.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected
earnings per share growth rates for the Gas Group are 4.81% by IBES/First Call,
5.07% by Zacks, 4.54% by Reuters/MarketGuide, and 4.67% by Value Line. The
Value Line projections indicate that earnings per share for the Gas Group will grow
prospectively at a more rapid rate (i.e., 4.67%) than the dividends per share (i.e.,
3.44%), which indicates a declining dividend payout ratio for the future. As
indicated earlier, and in Appendix E, with the constant price-earnings multiple
assumption of the DCF model, growth for these companies will occur at the higher
earnings per share growth rate, thus producing the capital gains yield expected by
investors.

Q. Is the five-year investment horizon associated with the analysts' forecasts
consistent with the assumptions implicit in the DCF model?
A. Yes. Investors do not view their expected returns as the product of an endless stream of growing dividends (e.g., a century of cash flows). Instead, it is the growth in the share value (i.e., capital appreciation, or capital gains yield), as represented by the analysts' forecast, that is most relevant to investors' total return expectations. Hence, the future appreciation in the price of a stock can be viewed as a "liquidating dividend" (i.e., the final cash flow associated with the ultimate sale of stock) that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms to the type of analysis that influences the total return expectation of investors.

Q. What conclusion have you drawn from these data?

A. Although ideally, historical and projected earnings per share and dividends per share growth indicators could be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, established that the best measure of
growth in the DCF model is forecasts of earnings per share growth. Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/MarketGuide, and Value Line, represents a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/MarketGuide and Value Line. The IBES/First Call, Zacks, and Reuters/MarketGuide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/MarketGuide estimates are obtained from the Internet and are widely available to investors free-of-charge. IBES/First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts, while Reuters/MarketGuide is a leading provider of financial data on the Internet. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company ("PUHC") act, merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell their shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility

---

companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities — such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth as shown on Schedule 9 provide a range of growth rates of 4.54% to 5.07%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. While the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.00% is within the array of earnings per share growth rates shown by the analysts’ forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As previously indicated, the consolidation now taking place in the utility industry, creates additional opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts’ forecasts that will enhance the growth prospects for the future. As such, a 5.00% growth rate will accommodate all of these factors.

Q. Please explain why the sum of the dividend yield and growth rate does not
provide a complete representation of the cost of equity.

A. As noted previously and as demonstrated in Appendix E, the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity ratio measured at book value, which is the measure used in calculating the weighted average cost of capital. This is the situation today where the market price of stock exceeds its book value for the companies in my proxy group. This divergence of price and book value creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility’s capitalization?

A. The capital structure ratios measured at the utility’s book value show more financial leverage, and hence higher risk, than the capitalization measured at its market values. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the
ratesetting process. Because the ratesetting process utilizes the book value capitalization when computing the weighted average cost of capital, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment that recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.70% (10.09% - 9.39%) for the Gas Group when the book value of equity, rather than the market value of equity, is used in determining the weighted average cost of capital for ratesetting purposes.

Q. Does the DCF model address the risk implications of small size of PPL Gas?

A. No. The DCF returns that are produced for the Gas Group relate to the average size of
that group. As noted previously, PPL Gas is considerably smaller than the Gas Group.

In order to provide some recognition of the additional return that is required to compensate PPL Gas for its small size, I have reviewed the difference in yields on A-rated and Baa-rated public utility debt. The yield difference is related to the additional return required when risk increases, i.e., generally bond yields increase as credit quality declines. Also, as size declines, risk likewise increases. There is a generally accepted tenet of corporate finance that risk and return are linked. In each instance, smaller size has more risk and weaker credit quality has more risk. The yield difference between A-rated and Baa-rated public utility bonds is used as a proxy for quantifying this additional risk.

As shown by the data presented on page 2 of Schedule 11, the difference in yields between A-rated and Baa-rated public utility bonds was 0.31% (6.07% - 5.76%) for the six-months ended February 2006. This yield difference can be added to the DCF calculation for the Gas Group to provide some recognition of the higher risk of PPL Gas due to its small size. Since the cost of equity includes a Risk Premium in addition to the cost of debt, the adjustment procedure that I advocate in this case provides only partial compensation for the addition risk of PPL Gas due to its small size.

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

A. As explained previously, I have utilized a six-month average dividend yield ("D_t/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously
developed. The DCF also includes the leverage modification ("lev."") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate that contains a size adjustment is:

\[ \frac{D_0}{P_0} + g + lev. = \alpha + \text{size} = K \]

Gas Group: \[ 4.39\% + 5.00\% + 0.70\% = 10.09\% + 0.31\% = 10.40\% \]

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that under this form of the DCF model, the indicated cost rate 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 because price-earnings multiples do not remain constant.

**RISK PREMIUM ANALYSIS**

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 G. I will summarize them here. With this method, 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. As with other models of the cost of equity, the Risk Premium approach has its limitations including an accurate assessment of the future cost of corporate debt and the measurement of the risk-adjusted common...
Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 6.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds for the rate effective period. As I will subsequently show, 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 10. For the twelve months ended February 2006, the average monthly yield on Moody’s A-rated index of public utility bonds was 5.66%. For the six and three-month periods ending February 2006, the yields were 5.76% and 5.79%, respectively.

Q. What are the implications of emphasizing recent data taken from a period of relatively low interest rates?

A. It appears obvious that if interest rates rise from current low levels, the overall cost of capital and cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates.

The low interest rates in 2003-’04 were, in part, the product of the Federal Open Market Committee (“FOMC”) policy, which is now in transition. Indeed, on June 30, 2004, August 10, 2004, September 21, 2004, February 10, 2004, December
DIRECT TESTIMONY OF PAUL R. MOUL

14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, and March 28, 2006, the FOMC increased the Fed Funds rate in fifteen 25 basis point increments. These policy actions, which have brought the Fed Funds rate to 4.75%, are widely interpreted as part of the process of moving toward a more neutral range for monetary policy. While short-term rates have increased significantly over the past twenty-one months, long-term rates have not moved similarly. This means that there has been a flattening of the yield curve. There is the potential for higher long-term interest rates, in the situation where the yield curve regains its normal upward slope as maturities are lengthened, and when short-term rates remain at current levels.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts (“Blue Chip”) along with the spread in the yields that I describe above and in Appendix G. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on 20-year Treasury bonds published on March 1, 2006 and the yield spread of 1.00% that I describe in Appendix G. For comparative purposes, I have also shown the Blue Chip forecast of yields of Aaa-rated and Baa-rated corporate
bonds. These forecasts are:

<table>
<thead>
<tr>
<th>Year</th>
<th>Quarter</th>
<th>Corporate Aaa-rated</th>
<th>Corporate Baa-rated</th>
<th>20-Year Treasury</th>
<th>A-rated Public Utility Spread</th>
<th>Yield</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>First</td>
<td>5.4%</td>
<td>6.4%</td>
<td>4.7%</td>
<td>1.0%</td>
<td>5.7%</td>
</tr>
<tr>
<td>2006</td>
<td>Second</td>
<td>5.7%</td>
<td>6.6%</td>
<td>4.9%</td>
<td>1.0%</td>
<td>5.9%</td>
</tr>
<tr>
<td>2006</td>
<td>Third</td>
<td>5.8%</td>
<td>6.8%</td>
<td>5.0%</td>
<td>1.0%</td>
<td>6.0%</td>
</tr>
<tr>
<td>2006</td>
<td>Fourth</td>
<td>5.8%</td>
<td>6.8%</td>
<td>5.1%</td>
<td>1.0%</td>
<td>6.1%</td>
</tr>
<tr>
<td>2007</td>
<td>First</td>
<td>5.9%</td>
<td>6.9%</td>
<td>5.1%</td>
<td>1.0%</td>
<td>6.1%</td>
</tr>
<tr>
<td>2007</td>
<td>Second</td>
<td>5.9%</td>
<td>6.8%</td>
<td>5.1%</td>
<td>1.0%</td>
<td>6.1%</td>
</tr>
</tbody>
</table>

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecast of interest rates. In its December 1, 2005 publication, the Blue Chip published forecasts of interest rates are reported to be:

<table>
<thead>
<tr>
<th>Year</th>
<th>Corporate Aaa-rated</th>
<th>Corporate Baa-rated</th>
<th>20-Year Treasury</th>
<th>A-rated Public Utility Spread</th>
<th>Yield</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>6.2%</td>
<td>7.1%</td>
<td>5.4%</td>
<td>1.0%</td>
<td>6.4%</td>
</tr>
<tr>
<td>2008</td>
<td>6.2%</td>
<td>7.1%</td>
<td>5.4%</td>
<td>1.0%</td>
<td>6.4%</td>
</tr>
<tr>
<td>2009</td>
<td>6.3%</td>
<td>7.1%</td>
<td>5.5%</td>
<td>1.0%</td>
<td>6.5%</td>
</tr>
<tr>
<td>2010</td>
<td>6.3%</td>
<td>7.2%</td>
<td>5.5%</td>
<td>1.0%</td>
<td>6.5%</td>
</tr>
<tr>
<td>2011</td>
<td>6.4%</td>
<td>7.2%</td>
<td>5.6%</td>
<td>1.0%</td>
<td>6.6%</td>
</tr>
</tbody>
</table>

Averages: 2007-11 6.3% 7.1% 5.5% 1.0% 6.5%

2012-16 6.4% 7.2% 5.6% 1.0% 6.6%

Given these forecasts of long-term interest rates, a 6.50% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix H provides a discussion of the financial returns that I relied upon to
develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks because it is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. The S&P Public Utility index is more closely aligned with these groups than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P public utilities have you determined for this case?

A. To develop an appropriate risk premium, I 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. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 11 the indicated risk premiums for the various time periods analyzed are 5.17% (1928-2005), 6.05% (1952-2005), 5.19% (1974-2005), and 5.20% (1979-2005). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and
removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 11 represents the returns realized through 2005. Second, the selection of the initial year of each period was based upon the events that I described in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 11, the 1928-2005 period provides the lowest indicated risk premiums, while the 1952-2005 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.20% (5.19% + 5.20% = 10.39% / 2) is shown from data covering the periods 1974-2005 and 1979-2005. Therefore, 5.20% represents a reasonable risk premium for the S&P Public Utilities in this case.
As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals among the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings; internally generated funds, and betas. In my opinion, these differences indicate that 5.00% represents a reasonable common equity risk premium in this case. This represents approximately 96% (5.00% ÷ 5.20% = 0.96) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

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

A. The cost of equity (i.e., “k”) is represented by the sum of the prospective yield for long-term public utility debt (i.e., “i”), the equity risk premium (i.e., “RP”). The Risk Premium approach provides a cost of equity of:

\[ \frac{1}{i + RP = k} \]

Gas Group 6.50% + 5.00% = 11.50%

As I noted previously, PPL Gas carries a “2” designation from NAIC on its debt. This means that the Risk Premium cost rate shown above would understate the Company’s cost of equity by 0.31% (6.07% - 5.76%), because the 11.50% is based on the yield on A-rated public utility debt.
DIRECT TESTIMONY OF PAUL R. MOUL

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 CAPM in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that create limitations in the model that I discuss in Appendix H. 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 that 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 uses the yield on a risk-free interest bearing obligation plus a rate of return premium that 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 H. To compute the cost of equity with the CAPM, three components are necessary: 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 portfolio of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group.

Q. What betas have you considered in the CAPM?
A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 12, the average beta is .82 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

\[ \beta_l = \beta_u [1 + (1 - t) \frac{D}{E} + \frac{P}{E}] \]

where \( \beta_l \) = the leveraged beta, \( \beta_u \) = the unleveraged beta, \( t \) = income tax rate, \( D \) = debt ratio, \( P \) = preferred stock ratio, and \( E \) = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at its market values, the beta would become .62 for the Gas Group if they employed no leverage and were 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of .97 for the Gas Group associated with book value capital structure.

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

A. For reasons explained in Appendix G, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of
Schedule 12, I provided the historical yields on 20-year Treasury bonds. For the
twelve months ended February 2006, the average yield was 4.65%, as shown on
page 3 of that schedule. For the six- and three-months ended February 2006, the
yields on 20-year Treasury bonds were 4.70% and 4.70%, respectively. As shown
on page 4 of Schedule 12, forecasts published by Blue Chip on March 1, 2006
indicate that the yields on long-term Treasury bonds are expected increase to 5.1%
during the next six quarters. The longer term forecasts described previously show
that the yields on Treasury bonds will average 5.5% from 2007 through 2011. I
have used a 5.50% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the CAPM?
A. As developed in Appendix H, the market premium is developed by averaging
historical market performance (i.e., 6.5%) and the forecasts (i.e., 5.95%). The
resulting market premium is 6.23% (6.5% + 5.95% = 12.45% / 2), which represents
the average market premium using the historical and forecast data.

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate
of return on common equity?
A. Yes. The technical literature supports an adjustment relating to the size of the
company or portfolio for which the calculation is performed. There would be an
understatement of the cost of equity using the CAPM unless the size of a firm is
considered. That is to say, as the size of a firm decreases, its risk, and hence its
required return increases. Moreover, in his discussion of the cost of capital,
Professor Brigham has indicated that smaller firms have higher capital costs then
otherwise similar larger firms (see Fundamentals of Financial Management, fifth
Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the SBBI Yearbook that stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, Gas Group has an average market capitalization of its equity of $1,600 million, which would place it in the sixth decile consisting of companies with market capitalization between $1,098 million and $1,608 million according to the size of the companies traded on the NYSE, AMEX, and NASDAQ. Although the Gas Group would technically be classified as a low-cap portfolio with its $1,600 million average market capitalization, I have taken a conservative approach to the size adjustment by employing a mid-cap adjustment. According to the SBBI Yearbook, the mid-cap size premium is 0.95%. Absent the size adjustment, the CAPM would understate the required return for the Gas Group. Of course, the size adjustment would be even greater for PPL Gas because if its stock were traded, it would likely be in the “micro-cap” category. The “micro-cap” size premium is 4.02% for CAPM purposes, thus showing the conservative nature of the size adjustment I employed for the Gas Group.

Q. **What CAPM result have you determined using the CAPM?**

A. Using the 5.50% risk-free rate of return, the leverage adjusted betas of .97 for the Gas Group, the 6.23% market premium, the size premium, and the flotation cost
adjustment developed previously, the following result is indicated.

\[ R_f + \beta \times ( R_m - R_f ) + size = K \]

Gas Group: 5.50% + 0.97 \times ( 6.23\% ) + 0.95\% = 12.49\%

**COMPARABLE EARNINGS APPROACH**

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

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public 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 companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate, if not necessary, to view the returns experienced by firms that operate in competitive markets. 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, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended
DIRECT TESTIMONY OF PAUL R. MOUL

by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

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 public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by
non-regulated firms have become increasingly relevant with the trend toward increased risk throughout the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1800 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships ("MLPs").

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Schedule 13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown.
DIRECT TESTIMONY OF PAUL R. MOUL

on page 2 of Schedule 13 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. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively 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. Unlike the DCF and CAPM, 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 approach does not contain the potential misspecification that results from applying the result of market models to an original cost rate base when prices and book values diverge significantly. The historical rate of return on book common equity was 14.4% using the median value as shown on page 2 of Schedule 13. The forecast rates of return as published by
Value Line are shown by the 14.5% median values also provided on page 2 of Schedule 14.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

<table>
<thead>
<tr>
<th></th>
<th>Historical</th>
<th>Forecast</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comparable Earnings Group</td>
<td>14.40%</td>
<td>14.50%</td>
<td>14.45%</td>
</tr>
</tbody>
</table>

The results of the Comparable Earnings method are not sensitive to stock market performance, but rather these results are determined from financial performance in competitive markets that are determined in large measure by the business cycle.

**CREDIT QUALITY**

Q. What are some of the important factors that influence credit quality?

A. The Company must have the financial strength that will, at a minimum, permit it to maintain a financial profile that is commensurate with the requirements to obtain a solid investment grade bond rating. 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. Customers also benefit from strong credit quality because the utility will be able to obtain lower financing costs that are passed on to customers in the form of a lower embedded cost of debt. For this reason, rates should be established that would allow the maintenance of a
DIRECT TESTIMONY OF PAUL R. MOUL

financial profile that would support a strong A-bond rating.

Q. What credit quality issues should be considered in this case for PPL Gas?
A. As noted previously, PPL Gas debt carries a “2” designation from the NAIC. This places the Company’s debt at the bottom of the investment grades (i.e., Baa/BBB). Due to its weak credit rating, the Company should be provided with an opportunity to experience a rate of return at the high end of the range.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion concerning the Company’s cost of common equity?
A. Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is within the range of 11.25% to 11.75% for the Company. The Company requested the high end of the cost of equity range to provide recognition of the high quality of its service as explained in the testimony of Mr. Rogala. In addition, the Company carries a “2” designation in the NAIC classification, its size is small, and its business risk characteristics, especially with regard to the threat of bypass from the interstate pipelines indicates that the rate of return on common equity should recognize these factors. It is essential that the Commission employ a variety of techniques to measure the Company’s cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this conclude your direct testimony?
A. Yes, it does.
Appendices A through I

to Accompany the

Direct Testimony

of

Paul R. Moul
Managing Consultant
P. Moul & Associates

Concerning

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 wastewater 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 financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine 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 thirty (30) federal,
state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory
Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida,
Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts,
Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina,
Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West
Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200
rate cases involving electric power, natural gas distribution and transmission, resource
recovery, solid waste collection and disposal, telephone, wastewater, and water service utility
companies. While my testimony has involved principally fair rate of return and financial
matters, 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.

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 have been the consultant to the New York Chapter of the National Association of Water Companies which represented 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). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

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 Society of Utility and Regulatory Financial Analysis (formerly 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.
APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL


My lecture and speaking engagements include:

<table>
<thead>
<tr>
<th>Date</th>
<th>Occasion</th>
<th>Sponsor</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 2000</td>
<td>EEI Member Workshop</td>
<td>Edison Electric Institute</td>
</tr>
<tr>
<td>February 2000</td>
<td>The Sixth Annual FERC Briefing</td>
<td>Exnet and Bruder, Gentile &amp; Marcoux, LLP</td>
</tr>
<tr>
<td>March 1994</td>
<td>Seventh Annual Proceeding</td>
<td>Electric Utility</td>
</tr>
<tr>
<td>April 1993</td>
<td>Twenty-Fifth Financial Forum</td>
<td>National Society of Rate Analysts</td>
</tr>
<tr>
<td>June 1992</td>
<td>Rate and Charges Subcommittee Annual Conference</td>
<td>American Water Works Association</td>
</tr>
<tr>
<td>October 1989</td>
<td>Seventeenth Annual Eastern Utility Rate Seminar</td>
<td>Water Committee of the National Association of Regulatory Utility of Florida Commissioners Florida, Public Service Commission and University of Utah</td>
</tr>
<tr>
<td>October 1988</td>
<td>Sixteenth Annual Eastern Utility Rate Seminar</td>
<td>Water Committee of the National Association of Regulatory Utility of Florida Commissioners Florida, Public Service Commission and University of Utah</td>
</tr>
<tr>
<td>May 1988</td>
<td>Twentieth Financial</td>
<td>National Society of Florida</td>
</tr>
</tbody>
</table>
# APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
<th>Location/Group</th>
</tr>
</thead>
<tbody>
<tr>
<td>October 1987</td>
<td>Forum Fifteenth Annual Eastern Utility Rate Seminar</td>
<td>Rate of Return Analysts Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah</td>
</tr>
<tr>
<td>September 1987</td>
<td>Rate Committee Meeting</td>
<td>American Gas Association</td>
</tr>
<tr>
<td>May 1987</td>
<td>Pennsylvania Chapter annual meeting</td>
<td>National Association of Water Companies</td>
</tr>
<tr>
<td>October 1986</td>
<td>Eighteenth Financial Forum</td>
<td>National Society of Rate of Return</td>
</tr>
<tr>
<td>October 1984</td>
<td>Fifth National on Utility Ratemaking Fundamentals</td>
<td>American Bar Association</td>
</tr>
<tr>
<td>March 1984</td>
<td>Management Seminar</td>
<td>New York State Telephone Association</td>
</tr>
<tr>
<td>February 1983</td>
<td>The Cost of Capital Seminar</td>
<td>Temple University, School of Business Admin.</td>
</tr>
<tr>
<td>May 1982</td>
<td>A Seminar on Regulation and The Cost of Capital</td>
<td>New Mexico State University, Center for Business Research and Services</td>
</tr>
<tr>
<td>October 1979</td>
<td>Economics of Regulation</td>
<td>Brown University</td>
</tr>
</tbody>
</table>
APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

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

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

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 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

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

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, it 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 recovery of costs associated with securing capital, 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.
APPENDIX C TO DIRECT TESTIMONY OF PAUL R. MOUL

EVALUATION OF RISK

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 all else being equal. Because 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 public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm 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, 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 not 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. Thus, 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.

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 firms 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, regulated firms 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.

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).
COST OF EQUITY—GENERAL APPROACH

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 except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, 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. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public 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.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free 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.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of 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 public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the landmark decisions on the issue of rate of return. These decisions require that a fair return for a utility must be equal to that earned by firms of comparable risk.
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 \div (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. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If $P$ represents price, $K_p$ 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, $K_p$. In this circumstance:
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

\[ P_0 = \frac{D_1}{(1 + K_p)} + \frac{D_2}{(1 + K_p)^2} + \frac{D_3}{(1 + K_p)^3} + \ldots + \frac{D_n}{(1 + K_p)^n} \]

1. 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:

\[ P_0 = \frac{D_1}{K_p} \]

2. 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 \( K_p = $1.00 / $10 \), or 10%.

3. 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 \( K_s \) (the required rate of return on a common stock) is greater than \( g \), then the DCF equation can be reduced to:

\[ P_0 = \frac{D_1}{K_s - g} \quad \text{or} \quad P_0 = \frac{D_0 (1 + g)}{K_s - g} \]

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

---

\(^1\) Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in...
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

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

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, \( K_s \) 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 a public 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

the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.
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.

**Use of DCF in Ratesetting**

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process 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, 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 \times .75 = $0.75, and $1.00 - $0.75 = $0.25 \div $8.00 = 3.125\%). In this example, the earnings retention growth rate plus the 6.25\% dividend yield ($0.75 \div $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. Were regulators to
use the results of a DCF model, that fails to produce the required return when applied to an
original cost rate base, they would penalize a company with high market-to-book ratios. This
clearly would penalize a regulated firm and its investors that 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.
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

Dividend Yield

The historical annual dividend yields are shown on and Schedule 3 for the Gas Group. The 2000-2004 five-year average dividend yield was 4.9% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 7. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

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

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

\[
K = \frac{D_0 (1 + g)^6 + D_0 (1 + g)^6 + D_0 (1 + g)^6 + D_0 (1 + g)^6 + D_0 (1 + g)^6 + g}{P_0}
\]

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.500% (5.00% x .5) for the Gas Group which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.38% (4.27% x 1.02500) for the Gas Group.

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

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

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.40% (4.27% x 1.03106) for the Gas 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:

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

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 ($D_0$):

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

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 1.0675% (4.27% ÷ 4) for the Gas Group. The compound dividend yield would be 4.39% (1.010806^4-1) for the Gas 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 the Gas Group, a 4.39% forward-looking dividend yield is the average (4.38% + 4.40% + 4.39% = 13.17% ÷ 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.

**Growth Rate**

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, 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. Since the traditional form of the DCF assumes no change in the price-earnings multiple, 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.
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

1. growth using company-specific variables.

2. Investors consider both historical and projected data in the context of the expected growth rate for a firm. 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 that 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 those expectations, 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). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

3. 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
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

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 that influence
the published projections. Of particular importance for regulated firms, Value Line considers
the regulatory quality, rates of return recently authorized, the historic ability of the firm to
actually experience the authorized rates of return, the firm's budgeted capital spending, the
firm'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 ("IBES"), which has been published for many years.
The IBES service provided data on consensus earnings per share forecasts and five-year
earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First
Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts.
The earnings estimates are obtained from financial analysts at brokerage research departments
and from institutions whose securities analysts are projecting earnings for companies in the
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

First Call universe of companies. Other services that tabulate earnings forecasts and publish
them are Zacks Investment Research and Market Guide (which is provided over the Internet by
Reuters). As with the First Call forecasts, Zacks and Reuters/Market Guide provide consensus
forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and
subsequent year receive prominent coverage. That is to say, First Call/Thomson, Zacks,
Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections
for the next year. 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
near-term earnings per share growth rates should also be factored into a growth rate
determination.

Although forecasts of future performance are investor influencing,
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. It is apparent
that any serious investor would advise himself/herself of historical performance prior to taking
an investment position in a firm. Earnings per share and dividends per share represent the
principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For
dexample, 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 "BxR" shown on Schedule 9. Internal growth rates are
often used as a proxy for book value growth. Unfortunately, this measure of growth is often

---

\(^2\) As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G.

E-12
not reflective of investor-expected growth. This is especially important 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.

**Leverage Adjustment**

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value for the purpose of determining the weighted average cost of capital is in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

<table>
<thead>
<tr>
<th>Capitalization at Market Value</th>
<th>Capitalization at Book Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Fair Value)</td>
<td>(Carrying Amounts)</td>
</tr>
<tr>
<td>Long-term Debt</td>
<td>32.29%</td>
</tr>
<tr>
<td>Preferred Stock</td>
<td>0.15</td>
</tr>
<tr>
<td>Common Equity</td>
<td>67.55</td>
</tr>
<tr>
<td>Total</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

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

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

\[
ku = ke - (((ku - i) \times (1-t)) \times \frac{D}{E}) - (ku - d) \times \frac{P}{E}
\]

\[
8.52\% = 9.39\% - (((8.52\%-5.76\%) \times 0.65) \times 32.29\%/67.55\%) - (8.52\% - 6.24\%) \times \frac{0.15\%}{67.55\%}
\]

where \( ku \) = cost of equity for an all-equity firm, \( ke \) = market determined cost equity, \( i \) = cost of debt\(^3\), \( d \) = dividend rate on preferred stock\(^4\), \( D \) = debt ratio, \( P \) = preferred stock ratio, and \( E \) = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.52% in the case of the Gas Group using the market value of the capitalization.

Having determined that the cost of equity for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

---

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

\(^4\) The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.
APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

1  \[ ke = ku + \left(\left( ku - i \right)(1-t) \right) \frac{D}{E} + \left( ku - d \right) \frac{P}{E} \]

2  \[ 10.09\% = 8.52\% + \left(\left( 8.52\% - 5.76\% \right) \cdot 0.65 \right) \frac{46.39\%}{53.38\%} + \left( 8.52\% - 6.24\% \right) \frac{0.23\%}{53.38\%} \]
INTEREST RATES

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

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

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity.
APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

**Interest Rate Environment**

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. 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. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous 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. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget 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 of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first
APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

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

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

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium
for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically
important 6% level for the first time since 1993.

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

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term
Congressional elections. The FOMC’s action was based upon concerns over how increasing
weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the
FOMC had been more concerned about fighting inflation than the state of the economy. The
initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-
term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury
yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely
anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third
reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the
Fed Funds rate to 4.75%. 
APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

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

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

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight
APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

labor markets, and a reversal of the monetary ease that was required earlier in response to the
global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence
began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC
reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate
to 5.50%. The FOMC described its actions as “a rapid and forceful response of monetary
policy” to eroding consumer and business confidence exemplified by weaker retail sales and
business spending on capital equipment and cut backs in manufacturing production.

21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points
decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate
to 3.50%. The FOMC observed on August 21, 2001:

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

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

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis
points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001
and followed the four-day closure of the financial markets following the terrorist attacks. The
second reduction occurred at the October 2 meeting of the FOMC where it observed:
APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

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

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

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

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

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

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

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

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

For the remainder of 2003, the FOMC continued with its balanced monetary policy,
thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of
moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates).
2006, the FOMC increased the Fed Funds rate in fifteen 25 basis point increments. These
policy actions are widely interpreted as part of the process of moving toward a more neutral
range for the Fed Funds rate. In its March 28, 2006 press release, the FOMC stated:

“The slowing of the growth of real GDP in the fourth quarter of 2005
seems largely to have reflected temporary or special factors.
Economic growth has rebounded strongly in the current quarter but
appears likely to moderate to a more sustainable pace. As yet, the
run-up in the prices of energy and other commodities appears to have
had only a modest effect on core inflation, ongoing productivity
gains have helped to hold the growth of unit labor costs in check,
and inflation expectations remain contained. Still, possible increases
in resource utilization, in combination with the elevated prices of
energy and other commodities, have the potential to add to inflation
pressures.

The Committee judges that some further policy firming may be
needed to keep the risks to the attainment of both sustainable
economic growth and price stability roughly in balance. In any
event, the Committee will respond to changes in economic prospects
as needed to foster these objectives.”

Public Utility Bond Yields

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

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

Pages 1 and 2 of Schedule 10 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 10. There, it is shown that those spreads were at about the one percentage point during the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 10, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in
1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.52% in 2003, 1.11% in 2004, and 1.00% in 2005. As shown by the monthly data presented on pages 4 and 5 of Schedule 10, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.02 percentage points for the twelve-months ended February 2006. For the six- and three-month periods ending February 2006, the yield spread was 1.06% and 1.09%, respectively.

**Risk-Free Rate of Return in the CAPM**

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 12 provide the yields on the broad spectrum of Treasury Notes and Bonds. 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)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that 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 FOMC monetary policy,
APPENDIX F TODIRECT TESTIMONY OF PAUL R. MOUL

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

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 because 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 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. Because no precise measurement exists as to the cost of equity, 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. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.
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.

**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. Because 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 that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas 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 detracts from the risk analysis, because 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
APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

1 investor would forego payment for the use of capital, or expect loss of principal, as a basis for
2 investing. Investors will hold cash rather than invest with the expectation of a loss.

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

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

17 The measurement procedure used to identify the risk rate differentials consisted of
18 arithmetic means, geometric means, and medians for each series. Measures of the central
19 tendency of the results from the historical periods provide the best indication of representative
20 rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the
21 arithmetic mean because a utility must expect to earn its cost of capital in each year in order to
22 provide investors with their long-term expectations. In other contexts, such as pension
23 determinations, compound rates of return, as shown by the geometric means, may be
appropriate. The median returns are also appropriate in ratesetting because 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.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate 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. For the years 1928 through 2005, the risk premiums for each class of equity are:

<table>
<thead>
<tr>
<th></th>
<th>S&amp;P Composite</th>
<th>S&amp;P Public Utilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arithmetic Mean</td>
<td>5.78%</td>
<td>5.27%</td>
</tr>
<tr>
<td>Geometric Mean</td>
<td>4.14%</td>
<td>3.18%</td>
</tr>
<tr>
<td>Median</td>
<td>8.94%</td>
<td>6.95%</td>
</tr>
<tr>
<td>Midpoint of Range</td>
<td>6.54%</td>
<td>5.07%</td>
</tr>
<tr>
<td>Average</td>
<td>6.16%</td>
<td>5.17%</td>
</tr>
</tbody>
</table>

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.
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 11 should also be considered. One of these sub-periods included the 54-year period, 1952-2005. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether 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 2005 and 1979 through 2005 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 54-year, 32-year and 27-year periods, the public utility risk premiums were 6.05%, 5.19%, and 5.20% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 11.
APPENDIX H TO 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 that 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 that found 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 which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average
APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

investor holds a well-diversified portfolio, the CAPM must also be used with other models of
the cost of equity.

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

\[
k = R_f + \beta (R_m - R_f)
\]

As previously indicated, it is important to recognize that the academic research has
shown 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. These tests indicated that for portfolios with betas
less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for
portfolios with betas above 1.0, these companies had lower returns than indicated by the
traditional CAPM theory. Once again, CAPM assumes 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 ($\beta$), 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 12 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

**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 ($R_{m} - R_{f}$). In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is
established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, 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 March 10, 2006, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 12) the total return on the universe of Value Line equities is:

<table>
<thead>
<tr>
<th>Dividend Yield</th>
<th>Median Appreciation</th>
<th>Median Total Return</th>
</tr>
</thead>
<tbody>
<tr>
<td>As of March 10, 2006</td>
<td>1.6% + 8.78%</td>
<td>10.38%</td>
</tr>
</tbody>
</table>

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.52%.

<table>
<thead>
<tr>
<th>DCF Result for the S&amp;P 500 Composite</th>
</tr>
</thead>
</table>
| D/P $\left(1 + 1.5g\right)$ + $g$ = $k$
| 1.90% $\left(1.05260\right)$ + 10.52% = 12.52% |

where: Price (P) at 28-Feb-2006 = 1280.66
Dividend (D) for 4th Qtr '05 = 6.08
Dividend (D) annualized = 24.32
Growth (g) First Call EPS = 10.52%

Using these indicators, the total market return is 11.45% (10.38% + 12.52% = 22.90% ÷ 2) using both the Value Line and S&P derived returns. With the 11.45% forecast market return and the 5.50% risk-free rate of return, a 5.95% (11.45% - 5.50%) market premium would be

---

1 The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{25} - 1$).
indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 12. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 12, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2005, the market premium was 6.5% (12.3% - 5.8%).

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

Arithmetic Versus Geometric Differences
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.

Arithmetic Versus Geometric Means
The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment’s cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to
APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.23% (6.5% + 5.95% = 12.45% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 5.95% using forecasts.
APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

COMPARABLE EARNINGS APPROACH

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

Timeliness Rank

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

Safety Rank

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

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.
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061398

PPL Gas Utilities Corporation

Statement No. 7

Direct Testimony of John J. Spanos
1 Direct Testimony of John J. Spanos

2 Q. Please state your name and business address.

3 A. My name is John J. Spanos, and my business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

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

6 A. I am employed by the Gannett Fleming, Inc., as Vice President of the Valuation and Rate Division.

9 Q. Please describe the Valuation and Rate Division of Gannett Fleming, Inc.

10 A. The Valuation and Rate Division of Gannett Fleming, Inc., a subsidiary of Gannett Fleming Affiliates, Inc., provides consulting services to public utilities and railroads. The Gannett Fleming affiliated companies employ nearly 2,000 people. Regional offices are maintained in 22 states and in Calgary, Alberta.

15 The Valuation and Rate Division of Gannett Fleming, Inc., and its predecessor, Gannett Fleming Valuation and Rate Consultants, Inc., have a long history of client services encompassing valuations; depreciation studies; revenue requirement, cost allocation and rate design studies; analyses of accounting systems; and acquisition and feasibility studies.

20 Q. Please state briefly your educational background and employment experience.

22 A. I have Bachelor of Science Degree in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.
Q. Are you a member of any professional societies?
A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?
A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003.

Q. What is the purpose of your testimony in this statement?
A. My testimony is in support of the depreciation studies conducted under my direction and supervision for PPL Gas Utilities Corporation ("PPL Gas").

Q. Have you previously prepared comparable studies for PPL Gas?
A. Yes. Prior to their merger with and into PPL Gas, I prepared exhibits for the depreciation study in North Penn Gas Company's rate proceeding at Docket No. R-00943245, and for PFG Gas, Inc. at Docket No. R-00932952. I also was responsible for the most recent combined depreciation study prepared for PPL Gas at Docket No. R-00005277.

Q. Have you previously testified on these subjects?
A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities...
1 Commission of Ohio, the Nevada Public Utility Commission, the Public Utilities
2 Board of New Jersey, the Missouri Public Service Commission and the
3 Massachusetts Department of Telecommunications and Energy, the Alberta
4 Energy & Utility Board, the Idaho Public Utility Commission, the Louisiana Public
5 Service Commission, the State Corporation Commission of Kansas, the
6 Oklahoma Corporate Commission, The Public Service Commission of South
7 Carolina, Railroad Commission of Texas – Gas Services Division, the New York
8 Public Service Commission, Illinois Commerce Commission, and the Indiana
9 Utility Regulatory Commission.

DEPRECIATION STUDY

Q. What was the purpose of the depreciation studies?

A. The purpose of the depreciation studies was to determine the depreciation
reserve as of December 31, 2006, and the annual depreciation accruals as of
December 31, 2006.

Q. Please describe what you mean by the term "depreciation".

A. My use of the term "depreciation" is in accord with the definition set forth in the
Uniform System of Accounts prescribed for Class A and Class B Public Utilities.
"Depreciation" refers to the loss in service value not restored by current
maintenance, incurred in connection with the consumption or prospective
retirement of gas plant in the course of service from causes which are known to
be in current operation, against which the company is not protected by
insurance. Among the causes to be given consideration are wear and tear,
decay, action of the elements, inadequacy, obsolescence, changes in the art,
changes in demand and requirements of public authorities.

In the studies that I performed and that are the basis for my testimony, I used the
straight line remaining life method of depreciation, with the average service life
and equal life group procedures, for most plant accounts. In the remaining life
method, the annual depreciation is based on a system of depreciation
accounting which aims to distribute the unrecovered cost of fixed capital assets
over the estimated remaining useful life of the unit, or group of assets, in a
systematic and rational manner. These methods and procedures were approved
by the Pennsylvania Public Utility Commission (Pa. PUC) for accounting
purposes in its Order at Docket No. P-850001 and subsequently used and
approved at Docket No. R-860535 for ratemaking purposes for North Penn. The
same methods and procedures were used for PFG at Docket No. R-00932952.
The same methods and procedures were adopted for the combined companies
at Docket No. R-00005277.

Q. Have you prepared exhibits presenting the results of your depreciation study?
A. Yes. Exhibits JJS-1 and JJS-2 present the results of the depreciation study as of
the end of the historic test year, December 31, 2005, and as of the end of the
future test year, December 31, 2006, respectively. In addition, I was responsible
Q. Have you determined accrued depreciation for ratemaking purposes as of December 31, 2006?

A. Yes, I have determined the ratemaking book depreciation reserve related to gas plant as of December 31, 2006, to be $83,871,438.

Q. How did you determine the accrued depreciation as of December 31, 2006?

A. The accrued depreciation as of December 31, 2006, results from the bring forward of accrued depreciation as of December 31, 2005, related to the gas plant of PPL Gas. Table 2 on pages III-8 through III-10 of Exhibit JJS-2 presents the bring forward of the book reserves from December 31, 2005 to December 31, 2006. Table 2 sets forth, by plant account, the depreciation reserve balances as of December 31, 2005, the estimated reserve activity, and the projected reserve balances as of December 31, 2006. The estimated reserve activity consists of depreciation accruals, projected retirements, projected salvage, projected cost of removal, and amortization of net salvage. The estimated depreciation accruals by plant account of Table 2 are calculated in Table 3 on pages III-11 and III-12 of Exhibit JJS-2. The projected depreciation reserve of $83,871,438 is totaled as of December 31, 2006, on column 8.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended December 31, 2006.

A. The depreciation accruals for the twelve months ended December 31, 2006, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of December 31, 2005, to the projected average plant balances.
The projected average balances and resultant accruals for the twelve months ended December 31, 2006, are presented in Table 3 on pages III-11 and III-12 of Exhibit JJS-2 and are based on the projected additions and retirements.

Q. With reference to Table 2, please explain what you mean by "the amortization of net salvage".

A. The amortization of net salvage is an annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on the experience during the preceding five-year period.

Q. Please explain the manner in which you projected the amortization of net salvage to be recorded during the twelve months ended December 31, 2006.

A. The amortization of net salvage for the twelve months ended December 31, 2006 is the annual average of the experienced net salvage for the period 2001 through 2005.

Q. Please explain the manner in which you projected salvage and removal costs that are shown on Table 2 of Exhibit JJS-2.

A. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal, as a percent of retirement amounts, for the period January 1, 2001 through December 31, 2005, to the projected retirement amounts for the twelve months January through December 2006.
Q. Have you determined the annual depreciation and amortization expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation and amortization expense is $6,876,220 and consists of $6,413,504 of annual accruals to recover original cost and $462,716 of net salvage amortization.

Q. How did you determine the annual accruals of $6,876,220?

A. The annual accruals to recover original cost of $276,141,964.71 include $6,413,504 for depreciation and $462,716 for the five-year amortization of net salvage. The determination of annual depreciation accruals consists of two phases. In the first phase, service life characteristics are estimated for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

Q. Please describe the first phase of the study, that is, the manner in which you estimated the service life characteristics for each depreciable group.

A. The service life study consisted of compiling historical data from records related to gas plant in service; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant
operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of gas plant?

A. The data consisted of the entries made by North Penn to record gas plant transactions during the period 1951 through 2003. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method. That method is the most appropriate when aged retirement data are available, because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve as plotted from the life table represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid
considerations in service life estimation. Iowa type survivor curves were used in these interpretations.

Q. Please explain briefly what an "Iowa-type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 40-R1.5 indicates an average service life of forty years; a Right modal, or R, type curve (the mode occurs to the right of average life for right modal curves); and a relatively low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. Have you physically observe plant and equipment in the field?
A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the company and observe representative portions of the plant. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes, that is, the calculation of composite remaining lives and annual depreciation accruals.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1992 and remaining lives consistent with the equal life group procedure for plant installed in 1992 and in later years.

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.
Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1992.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1992 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please outline the contents of Exhibit JJS-2.

A. Exhibit JJS-2 is presented in three parts. Introduction includes statements related to the scope of and basis for the depreciation study. Methods Used in
the Determination of Annual and Accrued Depreciation includes descriptions of
the estimation of survivor curves and the calculation of annual and accrued
depreciation and an explanation of the manner in which net salvage was
incorporated in the calculations.

Results of Study presents a description of the results, summaries of the
depreciation calculations, graphs and tables which relate to the service life study,
and the detailed depreciation and amortization calculations.

Table 1, pages III-5 through III-7 of Exhibit JJS-2, presents the estimated
survivor curve, the original cost at December 31, 2006, and the depreciation
reserve and calculated annual depreciation for each account or subaccount of
Gas Plant in Service. Table 2, pages III-8 through III-10 of Exhibit JJS-2
presents the bring forward to December 31, 2006, of the depreciation reserve as
of December 31, 2005. Table 3, pages III-11 and III-12 of Exhibit JJS-2 presents
the calculation of the depreciation amounts for the future test year. Table 4,
page III-13 of Exhibit JJS-2 presents the experienced and estimated net salvage
during the period January 1, 2002 through December 31, 2006.

The section, beginning on page III-14 of Exhibit JJS-2, presents the
results of the retirement rate analyses prepared as the historical bases for the
service life estimates. The section, beginning on page III-144 of Exhibit JJS-2
presents the depreciation calculations related to original cost. The tabulations
on pages III-148 through III-238 of Exhibit JJS-2 presents the calculation of
annual depreciation by vintage by account for each classification of Gas Plant in
Service. The tabulations on pages III-239 through III-241 of Exhibit JJS-2
presents the calculation of annual depreciation for plant that is common to the
operation of PPL Gas. The tabulation on pages III-242 through III-244 of Exhibit JJS-2 presents the retirements, salvage, and cost of removal by account for each year during the period 2002 through 2006.

Q. Please outline the contents of Exhibit JJS-1.

A. Exhibit JJS-1 includes a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of December 31, 2005. The descriptions and explanations presented in Exhibit JJS-2 are also applicable to the depreciation calculations presented in Exhibit JJS-1. The graphs and tables related to service life presented in Exhibit JJS-2 also support the service life estimates used in Exhibit JJS-1, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2005, are organized and presented in the same manner as those as of December 31, 2006.

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in Exhibit JJS-2 using an account as an example.

A. I will use Account 367, Mains, to illustrate the manner in which the study was conducted. Account 367 represents 14 percent of the total depreciable plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2003. These data have been coded in the course of PPL Gas's normal recordkeeping according to account or property
group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The retirements, and other plant transactions, and plant additions were analyzed by the retirement rate method.

The Iowa 61-R2.5 survivor curve, was judged most appropriate for this account. This historical indication is that an Iowa 61-R2.5 survivor curve is being experienced, based on the statistical analysis for the 52-year history, 1951-2003. The original and smooth survivor curves are plotted on page III-64 of Exhibit JJS-2. The original life table for the 1951-2003 experience band is set forth on pages III-65 through III-67.

The calculation of annual depreciation, the second phase, for the original cost of Mains in service at December 31, 2006, is presented, by vintage, on pages III-185 through III-187 of Exhibit JJS-2 for Gas Plant in Service. In these calculations, a survivor curve was developed for each vintage, 1900 through 1992, through the use of a computer, using retirement ratios from the Iowa 61-R2.5 survivor curve through December 31, 2006. The expectancy and average life derived from the developed survivor curve for each vintage were used to calculate the accrued depreciation.

The accrued depreciation for vintages subsequent to 1992 is calculated by the equal life group procedure using the Iowa 61-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer, into depreciable groups according to the expected service lives as defined by the Iowa 61-R2.5 survivor curve. The accrued depreciation is derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.
The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 61-R2.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

Q. Is the procedure you described for Account 367 typical of that followed for most of the plant investment?
A. Yes, it is, inasmuch as the straight line method and vintage group average service life and the equal life group procedures were used for most of the depreciable plant.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.
A. The life span procedure was applied to structures in Accounts 375.1 and 390. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in the detailed section of the exhibits.

Q. In what manner is net salvage incorporated in the depreciation calculations?
A. As stated on pages I-4 and II-35 of Exhibit JJS-2 no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation expense reflects an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The
amortization is based on experience during the period 2001 through 2005 for the pro forma expense as of December 31, 2005, and on experience 2002 through December 31, 2005, plus estimates for the twelve months ending December 31, 2006, for the pro forma expense as of December 31, 2006. The detail by plant account of salvage and cost of removal for each year is presented on pages III-243 and III-244 of Exhibit JJS-2. The totals are brought forward to Table 4 on page III-13 of Exhibit JJS-2, in which the amounts of the five-year amortizations are calculated.

Q. Does this conclude your direct testimony?

A. Yes, it does.
BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061398

PPL Gas Utilities Corporation

Statement No. 8

9/25/06

Direct Testimony of Paul R. Herbert
Direct Testimony of Paul R. Herbert

Q. Please state your name and business address.
A. My name is Paul R. Herbert. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. By who are you employed?
A. I am employed by Gannett Fleming, Inc.

Q. Please describe your position with Gannett Fleming, Inc. and briefly state your general duties and responsibilities.
A. I am Senior Vice President of the Valuation and Rate Division. My duties and responsibilities include the preparation of accounting and financial data for revenue requirement and cash working capital claims, the allocation of cost of service to customer classifications, and the design of customer rates in support of public utility rate filings.

Q. Have you presented testimony in rate proceedings before a regulatory agency?
A. Yes. I have testified before the Pennsylvania Public Utility Commission, the New Jersey Board of Public Utilities, the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Kentucky Public Service Commission, the Iowa State Utilities Board, the Virginia State Corporation Commission, the Tennessee Regulatory Authority, and the
Missouri Public Service Commission concerning revenue requirements, cost of service allocation, rate design and cash working capital claims. A list of the cases in which I have testified is provided at the end of my direct testimony.

Q. What is your educational background?
A. I have a Bachelor of Science Degree in Finance from the Pennsylvania State University, University Park, Pennsylvania.

Q. Would you please describe your professional affiliations?
A. I am a member of the American Water Works Association and serve as a member of the Management Committee for the Pennsylvania Section. I also am a member of the Pennsylvania Municipal Authorities Association. In 1998, I became a member of the National Association of Water Companies, as well as a member of its Rates and Revenue Committee.

Q. Briefly describe your work experience.
A. I joined the Valuation Division of Gannett Fleming Corddry and Carpenter, Inc., predecessor to Gannett Fleming, Inc., in September 1977, as a Junior Rate Analyst. Since then, I advanced through several positions and was assigned the position of Manager of Rate Studies on July 1, 1990. On June 1, 1994, I was promoted to my current position as Vice President.

While earning my degree, I was employed during the summers of 1972, 1973 and 1974 by the United Telephone System - Eastern Group in its
accounting department. Upon graduation from college in 1975, I was employed by Herbert Associates, Inc., Consulting Engineers (now Herbert Rowland and Grubic, Inc.), as a field office manager until September 1977.

COST OF SERVICE ALLOCATION STUDY

Q. What was the purpose of the cost of service allocation study?
A. The purpose of the study was to allocate the total cost of service to the several service classifications. The study provides a basis for determining the extent to which the revenues to be derived from each classification are commensurate with the cost of serving that classification.

Q. What method of cost allocation was used in the study?
A. I used the Average and Extra Demand Method which is described in Exhibit PRH-1 and in the text, "Gas Rate Fundamentals", published by the American Gas Association's Rate Committee.

Q. Please describe Exhibit PRH-1.
A. Exhibit PRH-1 titled, "Cost of Service Allocation Study as of December 31, 2006," is the report on the cost of service allocation study prepared for PPL Gas Utilities Corporation. It sets forth the results of the study based on the projected costs and conditions during the twelve months ended December 31, 2006. The data in the exhibit include a description of the methods and procedures used in the study, the allocations of cost of service and measure of value, the factors on which the allocations were based and the application of rates to an analysis of customer consumption.
Q. Please outline the procedure which you followed in the cost allocation study.

A. The detailed allocation of costs to cost functions and customer classifications is presented in Schedule E, pages II-6 through II-11, of Exhibit PRH-1. Gas costs are excluded from the amounts in Schedule E in order to develop costs by function and classification related to the delivery of gas. Gas costs are allocated to sales customers in the cost of service summary set forth in Schedule D.

In the detailed allocation, the items of cost, which include operating expenses, depreciation expense, taxes, and income available for return, are identified in column 1 of Schedule E. The cost of each item, shown in column 3, is allocated to the several service classifications. The reference codes entered in column 2 enable one to determine the specific basis for the allocation of each item. The reference codes refer to the information presented in Schedule F, beginning on page II-12, of the exhibit.

Referring to some of the larger delivery cost items, transmission costs were allocated partly on the basis of average consumption and partly on the basis of demand in excess of average, extra demand, inasmuch as the function of these facilities is to meet peak requirements. Costs related to meters in Account 381 and the associated house regulators were allocated to service classifications on the basis of the number of equivalent meters by classification. Costs related to industrial measurement and regulation were allocated to the General - Large and Large Volume Service on the basis of equivalent meters in Account 385. Costs related to services were allocated...
on the basis of the equivalent number of services by classification. The
costs related to distribution mains and distribution measuring and regulating
stations were allocated on the bases of average daily consumption and extra
demand.

Q. How were storage costs allocated?
A. I have allocated storage demand costs based on the withdrawal capability
reserved for retail customers, 9,518 Dth, and the withdrawal capability
purchased by storage customers, 167,800 Dth. I have allocated storage
capacity costs based on the capacity reserved for retail customers, 899,300
Dth, and the capacity purchased by storage customers, 12,623,768 Dth.

Q. Please describe the allocation of customer accounting costs and the
remaining cost of service elements.
A. Customer accounting costs were allocated to service classifications on the
basis of the number of customers. Administrative and general costs were
allocated on the basis of the allocated direct costs, excluding those costs
requiring little administrative and general expense.

Annual depreciation accruals were allocated on the basis of the
function of the facilities represented by the depreciation expense for each
depreciable plant account. The original cost less depreciation of utility plant
in service was similarly allocated for the purpose of allocating certain taxes
and return.
Q. Did you prepare an analysis of customer costs?

A. Yes. The analysis of customer costs is presented in Schedule J of Exhibit PRH-1.

Q. Please explain the analysis of customer costs as set forth in Exhibit PRH-1.

A. The customer costs were determined by first allocating the cost of service to cost functions. The customer cost function was then allocated to service classifications. The volumetric and customer functional costs were determined by an allocation of the total cost of service to these functions in Schedule E of Exhibit PRH-1. The customer costs were further allocated to the Residential, General Service - Small, General Service - Large, and Large Volume Service classifications in the same schedule. The factors which were the bases for the allocation to cost functions and the allocation of customer costs to classifications are presented in Schedule F. A summary of the customer costs and the development of cost-based customer charges are presented in Schedule J.

Q. Did you prepare an analysis of costs related to the demand charge for Large Volume Service?

A. Yes. The analysis of costs related to the demand charge for Large Volume Service is presented in Schedule K of Exhibit PRH-1.
Q. Please explain the analysis of the Large Volume Service costs related to demand charges as set forth in Exhibit PRH-1.

A. The costs related to Large Volume Service demand charges were determined by the allocation of certain fixed costs, depreciation, taxes and return to this classification. The allocation was performed in Schedule E. A summary of the allocated costs and the development of the unit demand cost are presented in Schedule K.

Q. Does that conclude your direct testimony?

A. Yes, it does.