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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

Statement No. 1

Direct Testimony of Morgan K. O'Brien

DIRECT TESTIMONY OF MORGAN K. O'BRIEN

Q. Please state your full name and business address.

A. My name is Morgan K. O'Brien. My business address is 411 Seventh Avenue, Pittsburgh, PA 15219

Q. What is your position at Duquesne Light Company ("Duquesne Light" or "Company")?

A. I am President and Chief Executive Officer.

Q. How long have you worked at Duquesne Light?

A. I have worked at the company for the past 14 years in various executive positions in the Finance and Corporate Development areas. I have been Chief Executive Officer of Duquesne Light since 2001.

Q. **What are your qualifications, work experience and educational background?**

A. These are attached as Exhibit MKO-1.

Q. Please briefly describe the subject matter of your testimony in this proceeding.

A. The purpose of my testimony is to provide an overview of Duquesne Light and its requested base rate increase. First, I will explain the company's current financial condition. Second, I will describe our initiatives to manage costs while providing high quality and reliable electric service to customers. Third, I will describe our infrastructure capital construction program and its importance for our customers. Fourth, I will provide an overview of our request and explain why a base rate increase is necessary at this time. Finally, I will discuss the importance of this case to Duquesne Light, its customers, southwestern Pennsylvania and Pennsylvania's electric utility industry.

Q. What is Duquesne Light's current overall financial condition?

A. For calendar year 2005, Duquesne Light had operating income for the Pennsylvania jurisdiction of approximately $47.99 million, which equates to an overall return on rate base of 4.2 percent, with a corresponding return on common equity of 1.46 percent (using year-end balances). Our financial condition will decline in 2006 due to continued increases in expenses and capital expenditures for our infrastructure improvement program. On a pro forma basis for 2006, we anticipate operating income for the Pennsylvania jurisdiction of only $33.73 million and an overall return on rate base of about 2.7 percent, with a return on common equity of negative 1.48 percent (using year-end balances). These financial results clearly do not provide an adequate return to existing shareholders and will not permit the company to attract new capital on reasonable terms. Duquesne Light's senior unsecured debt currently is rated BBB- by S&P and Fitch and Baa2 by Moody's. These are among the lowest investment grade ratings. Without substantial rate relief, Duquesne Light's debt rating most likely would be downgraded to junk status, which would result in much higher capital costs and would seriously jeopardize the company's ability to complete its necessary infrastructure improvement program. Revenues at present rates simply do not provide sufficient funds for Duquesne Light to continue to operate its business and provide reliable electric service to its customers.

Q. What has caused this decline in Duquesne Light's financial condition?

A. Duquesne Light has not had a rate case since 1987, and, during recent years (1997-2004), we were subject to rate caps, which prevented us from raising rates. The cost of providing electric service has increased substantially over the past 20 years. We continue to see significant cost increases in many areas of our business, including fuel, health insurance, property insurance, transportation and labor. For example, since 1987, the price of a line truck has increased 43 percent, the price of mailing customers bills has increased 67 percent, and the company's cost for employee health insurance has increased by 500 percent. In addition, as detailed later in my testimony, we have initiated a significant capital investment program involving our electric infrastructure, designed to ensure that Duquesne Light continues to provide the levels of service and reliability our customers expect. This infrastructure initiative will further strain Duquesne Light's finances.

Q. What has been Duquesne Light's response to these increased costs?

A. We have been proactive and aggressive in managing our costs while maintaining and improving reliability and customer service. We have implemented significant process improvements and negotiated effective, long-term labor contracts that enabled us to manage our O&M expenses while, at the same time, delivering the levels of service and reliability that satisfy our customers. However, we have reached the point where we no longer are able to offset increasing O&M expenses through these types of initiatives, and we must make significant capital expenditures to continue to ensure reliable service for our customers. As a result, we must seek to increase our rates to recover our current cost of service, as well as the cost of new investments to serve customers.

Q. Please describe some of Duquesne Light's efforts to control costs.

A. In an era of sweeping changes in the utility industry, including the introduction of customer choice, Duquesne Light management has worked hard to meet our customers' need for high-quality service and reliability without raising rates. Most notably, we have aggressively reviewed and restructured key operating processes through an effort we refer to as "Best in Class." This process analysis, which focused on costs, reliability, customer satisfaction and safety, resulted in major changes in the way we do business, with corresponding reductions in costs and improvements in customer satisfaction.

During this review of our operating processes, the company conducted an in-depth analysis of day-to-day activities to identify performance-improvement opportunities in many areas, including service restoration, work management and administrative support. Employee work teams redesigned core processes to take advantage of these improvement opportunities. This analysis resulted in the creation of system-wide asset and work management processes, a streamlined management team, a redesigned process for restoration of service, a new approach to vegetation management and significant improvements to our customer call center.

The centerpiece of Duquesne Light's process-based philosophy has been listening to what customers want and then cost effectively satisfying their needs. While helping the company to successfully manage costs, the redesign of our processes also has led to improvements in customer service while maintaining reliability. Customer satisfaction ratings increased substantially through 2003 and have remained high through 2005. In addition, Duquesne Light has exceeded the PUC reliability standard for customer average interruption duration (CAIDI) every year since it was established in 1999. The company consistently has been ranked among the highest in the state in PUC reliability standards during that same time frame.

Duquesne Light customer satisfaction levels have been at an all-time high. We have steadily improved customer access to Duquesne Light through direct contact with our knowledgeable customer service representatives; our user-friendly website; and our interactive voice response system, which provides around-the-clock access to a variety of information and services. In addition, over the past five years, our automated meter reading system has virtually eliminated estimated bills. In fact, more than 99.5 percent of the more than 6.4 million bills that Duquesne Light sent to residential customers last year were based on actual meter readings. By using actual readings – rather than estimates – bills reflect a customer's true electric usage.

Prior to restructuring, Duquesne Light had approximately 5,000 employees. Today, the company has approximately 1,370 employees. While a number of these employees left when our generation assets were sold, staffing levels on the distribution and transmission side also were reduced as part of this initiative. Importantly, most of these reductions focused on overhead costs involving positions in "back-office" and support settings. They did not involve people in the field who restore electric service or install new services.

These efforts also resulted in fewer layers of management and more efficient decision-making processes. This leaner management team is highly focused on customer service, reliability, cost management, safety, community development, and statewide utility and economic-development issues.

We also have increased efficiency and maintained reliability through the use of technology, such as our automated meter reading system and the automated devices that can be used to re-route power during storms and other outages to quickly restore service to large blocks of customers. For example, we leveraged our System Control and Data Distribution System to enhance our reliability and service restoration processes. In addition, we have gained efficiencies through restructuring of key contracts. For example, fixed-price, performance-based contracts with vegetation management contractors have played a major role in a 25-percent reduction in tree-related outages while also keeping related costs under control. We also successfully negotiated a contract with our union employees that will help the company manage rising health care costs through cost-sharing.

Through these efforts, and other initiatives, Duquesne Light has been able to deliver the levels of service and reliability that satisfy our customers while maintaining solid financial performance in the face of increasing costs, without filing a base rate case since 1987. This is a remarkable achievement and is a tribute to the company and its dedicated employees. However, rate relief no longer can be delayed.

Q. Please describe the Company's infrastructure improvement plan.

A. Utility infrastructure is all around us, but most people do not really think about it or even realize it is there, unless they are experiencing a problem. However, recent events, such as the water main break in downtown Pittsburgh last summer, the bridge collapse on Interstate 70 in Washington County in December, and the Northeast/Midwest Blackout in 2003, dramatically illustrate the importance of utility infrastructure. Last summer's major water main break in downtown Pittsburgh resulted in flooding, extensive damage to property, closed many businesses for more than a week, and displaced residents for an even longer period of time. Similarly, this Commission is well aware of the economic and personal toll resulting from the Blackout of 2003, which reinforced the need for adequate electric infrastructure and proper vegetation control.

Governor Rendell has stated that one of the critical elements of his Plan for a New Pennsylvania is economic development. Critical to the state's economic development is its infrastructure. We live and work in a state that is aging – both in terms of our people and our infrastructure. To address this issue, the governor has set aside significant funding to support needed upgrading of the state's infrastructure. However, he also recognizes that the private sector must provide a significant portion of the required investment. Our plan is to invest more than $500 million in our electrical infrastructure and supporting facilities for our employees during the three-year period 2005 through 2007. We believe this will provide Allegheny and Beaver counties with the electric delivery system required to serve our customers and support economic development.

Duquesne Light's customers rely on continuous and efficient utility service. To meet that commitment, we systematically analyze circuits that carry electricity across our service territory. Through the years, the company has regularly replaced existing wires, poles and other equipment with new facilities in order to keep customers connected to a secure, reliable source of electricity.

While Duquesne Light's transmission and distribution system has served customers well for decades, significant capital investment is necessary to meet the following service obligations:

- to replace equipment that is damaged by factors such as wind, ice or heat, and to replace equipment that fails in service;
- to add or modify our system as a result of specific requests by customers and to meet our obligations to local, state and federal agencies to relocate our facilities;
- to ensure distribution system service capacity and reliability to meet the needs of our customers, including circuit conversions, the installation of new equipment to replace deteriorated, obsolete, or failed equipment, and additions that may be necessary to improve operations; and
- to provide supporting infrastructure, such as new vehicles, information technologies and a new service center and training facility being built in Pittsburgh to ensure our customers will continue to be served by a highly skilled, properly trained and efficient workforce in the future.

These and other projects also will help to meet growing concerns about safety and security, which have become even more important after Sept. 11, 2001, and the Blackout of 2003.

To address these service obligations, we plan to invest more than $500 million in capital expenditures during the 2005 through 2007 period in our infrastructure in order to ensure that Duquesne Light continues to provide the levels of service and reliability our customers expect. This capital investment will take place throughout our service territory. Major projects include:

- upgrading underground lines and equipment that have been in service in some suburban neighborhoods as far back as the 1960s;
- improving power capacity to serve the expanding electricity needs of hospitals and universities in the Oakland area;

- refurbishing and reinforcing the aging underground systems that provide service to sections of downtown Pittsburgh and surrounding urban and commercial areas;
- upgrading transmission lines that will improve the flow of electricity in the eastern part of our service territory, better balance the load throughout our service territory, and provide voltage support to this part of our system; and
- converting older distribution circuits to make use of newer technology to improve reliability.

Investing in our infrastructure not only provides the necessary services and reliability to meet our obligation as a regulated utility, but also will result in new employment, wages, tax receipts and spin-off economic development for our area. To help us complete these projects, we added approximately 150 full-time employees to the Duquesne Light workforce. In addition, approximately 150 project-specific positions will be available to skilled trades people in the region over the next several years. Increased employment resulting from the infrastructure work will have a positive impact on the economy of Pennsylvania.

Since 1880, Duquesne Light has been part of the fabric of Pittsburgh, working hard to enhance the quality of life for our customers. Maintaining the integrity and strength of the electrical service we provide through the infrastructure investment program is the latest example of that commitment.

Q. What effect will this plan have on Duquesne Light's financial condition?

A. Obviously, the capital investment required to fund this program will further stress Duquesne Light's already precarious financial condition. Funding for these projects will require substantial capital expenditures and, without rate relief, will further erode our income and financial integrity. Duquesne Light needs to be financially healthy and have acceptable credit ratings so that it can raise capital at a reasonable cost. Without adequate rate relief in this proceeding, the company will not be able to raise the capital necessary to complete these important projects.

Q. **Please describe the rate increase requested by the Company in this proceeding?**

A. Duquesne Light is requesting an increase of approximately $144 million in distribution rates and is notifying the Commission of an anticipated $19 million increase in retail transmission rates, to be effective on or about January 1, 2007. The distribution rate increase is designed to recover Duquesne Light's Pennsylvania jurisdictional cost of providing distribution service to its customers. The retail transmission rate increase reflects the expense we expect to incur subsequent to our FERC filing, under the FERC-approved PJM open access transmission tariff (OATT), to provide retail transmission service to customers who take provider-of-last-resort (POLR) service from Duquesne Light. We are requesting that the PUC incorporate these new transmission rates into the total rates set at the conclusion of this case. Accordingly, we have included the anticipated increase in transmission rates as part of this filing.

The total $163 million increase represents a system-wide average increase of approximately 13 percent for customers who receive POLR service from Duquesne Light, and will vary depending on their actual usage characteristics.

Q. **Please describe other key elements of the filing.**

A. In addition to the overall rate increase, the company is proposing to simplify its rate structure and to develop rates that more accurately reflect its new role as a "wires" company. We have performed a thorough jurisdictional separation of our transmission and distribution assets to properly divide our costs. We also have prepared a detailed cost-of-service study to allocate costs to our customer classes and subsequently to our individual rate schedules. Based on these studies, we have attempted to design rates which will: (1) simplify our rate schedules, (2) eliminate unneeded rate schedules or provisions that were developed when the company offered fully bundled electric service, and (3) better reflect class cost of service while applying principles of gradualism to avoid disparate rate impacts.

Duquesne Light also is proposing two new rate mechanisms: (1) a Distribution System Improvement Charge (DSIC) and (2) a Transmission Service Charge (TSC). The DSIC is designed to permit timely recovery of certain distribution investments made to serve customers. We are proposing a DSIC because we believe it mitigates rate impacts to customers and allows rates to increase more gradually than through the filing of much larger base rate increases. A DSIC fits well with our plan to support the region and additional investment subsequent to 2006.

We recognize that there currently is substantial doubt as to the Commission's authority to approve a DSIC mechanism for electric distribution companies. However, we believe this is an important proposal and are presenting it for approval in the event there is a change in law during the course of this proceeding. Alternatively, if the Commission cannot approve a DSIC mechanism, we believe it should consider, in setting Duquesne Light's return on equity, the regulatory lag the company will face between the time of implementing its infrastructure-improvement program and subsequent recovery in a future rate case.

The TSC is designed to permit the company to recover its costs of providing retail transmission service to customers, on a dollar-for-dollar reconcilable basis. These costs are incurred pursuant to the FERC-approved PJM OATT. The TSC will assure that the company does not over or under recover the cost of providing retail transmission service and will provide competitively neutral transmission rates.

Finally, and of critical importance, the company is proposing a significant expansion of its Customer Assistance Program (CAP) to serve low-income customers. CAP participants pay a percentage of their budgeted bill for current electric service, and arrearages are forgiven over time.

Increasing natural gas prices have put a strain on the budgets of low-income residents. We are proposing, as part of our filing, that monthly electric bill payments for those in our CAP program remain at current levels and not be impacted by the rate increase. We also propose to expand the enrollment of low-income customers in Duquesne Light's CAP from 23,000 at the end of 2005 to 25,000 in 2006 and 27,000 in 2007. To do that, our filing calls for a $2 million increase to cover our increased CAP enrollment for 2007 and a $6 million increase to keep our CAP customer payments the same after the rate increase. Without approval of this cost recovery by the PUC, we will not be able to fund the proposed expansion of this important program for our low-income customers.

In addition to CAP, we implemented five new Stay Warm energy assistance initiatives, designed to help restore service to low-income customers and provide other working poor customers credits of up to $150 to offset arrearages on their accounts during the winter of 2005-06. More than 8,800 low-income and working-poor customers took part.

Duquesne Light's Stay Warm program, which was recognized as a model program and was quickly approved by the PUC, cost more than $1 million. The costs of this special program for the winter of 2005-2006 were paid for by Duquesne Light shareholders. We are not seeking to recover costs incurred for the Stay Warm program during the past winter. However, we do propose to continue these programs, and the future costs of Stay Warm are included in our rate request.

Q. Can you place Duquesne Light's present and proposed rates in historic context?

A. Yes. The company's last base rate increase was approved by the Commission in 1987. The rates approved in that case were unbundled as part of Duquesne Light's electric restructuring in 1998. Specifically, our rates were divided into four components: generation, CTC (for stranded cost recovery), transmission and distribution. Due to the successful divestiture of our generation assets, our CTC collection was completed, with limited exceptions, in January 2003, long before other major utilities in the state. Early elimination of the CTC resulted in significant rate decreases for customers. As a result, Duquesne Light's rates today are lower than they were in 1992.

In real terms, the reduction in Duquesne Light's rates is even more dramatic. The general rate of inflation, as measured by the Consumer Price Index, has increased 55 percent since 1992 while Duquesne Light rates have decreased by 23 percent since 1992. Attached is Exhibit MKO-2 to illustrate our rates since 1992 and the Consumer Price Index.

Even with the proposed rate increase, customers' rates will be lower, even in nominal terms, than they were in 1992. The proposed new rate for an average non-heating residential customer would be about 12.6 cents/kWh, which is about 10 percent less than what that customer paid 15 years ago. The proposed new rate for a small commercial/industrial customer with 25 kw of demand using 10,000 kWh per month would be about 8.4 cents/kWh, which is about 12 percent less than what that customer paid 15 years ago.

By way of comparison, pricing for other utilities has increased significantly during that same time frame. Natural gas prices for residential customers in Pennsylvania have increased by approximately 115 percent since 1992. Nationally, the average water and sewerage rates have increased by 64 percent while the average cost of cable and satellite TV service has increased 78 percent, according to the U.S. Dept. of Labor Bureau of Labor Statistics.

Q. **Mr. O'Brien, please describe the importance of this rate increase request.**

A. This request is critical for Duquesne Light, its customers, southwestern Pennsylvania and the Commonwealth. Completion of our infrastructure program is a top priority. As I have said, aged and deteriorating equipment on our system must be replaced, and newer equipment needs to be installed to maintain and, in some cases, enhance reliability and to meet growth in certain areas within our service territory, such as the university and hospital sections of the Oakland section of Pittsburgh. Moreover, there clearly are limits to how long a company can rely on process and productivity improvements to offset increasing expenses without increasing prices. Duquesne Light has not filed for a distribution rate increase in nearly 20 years. We now must file a rate case to reflect our current cost of service.

In addition, adequate rate relief will provide the company with an opportunity to improve its financial condition. Improved credit ratings will benefit both customers and shareholders because we will be able to raise capital at a lower cost. Investors and analysts in the financial community will closely watch this case. In a recent report to utility investors, Lehman Brothers outlined 42 rate case filings occurring in 2006 and 2007 throughout the United States. They specifically raised a caution flag for investors in our company because of the tougher regulatory climate they perceive currently exists in Pennsylvania. At the same time, they encouraged investment in utilities with what they perceive are constructive regulatory jurisdictions in California and Ohio. Reports like these truly influence investors. They send a message throughout the financial community that translates into real costs to companies. As a result, this case is very important for all Pennsylvania utilities. It will send a loud, strong signal to investors as to whether they should invest in and lend monies to Pennsylvania utilities. It is very important that Duquesne Light receive adequate rate relief and a fair return to investors and other stakeholders in this case.

Finally, and perhaps more importantly, in order to maintain our role as a committed public service provider, a key employer and a long-time community partner in the Pittsburgh region, Duquesne Light needs to remain financially healthy. Pittsburgh is a city still recovering from the loss of the steel industry. When we look back on how much of the region's economy was directly tied to the steel industry, it is not surprising that it has been such a long and challenging climb back. However, as a region, we have made incredible economic progress. In the areas of health care and with our universities, we are recognized as a national leader. At the same time, the importance of Duquesne Light to this community has grown larger as the region's overall corporate citizenship has greatly been reduced. Historically, large corporations have been the backbone of support for social and human services in most areas of the country. With losses of large multi-national companies, such as Gulf Oil, Rockwell International and Westinghouse, there are fewer and fewer good corporate citizens that serve and support our community's needs.

At a time when fewer corporations were available to jointly sit around the table and address the community's needs, Duquesne Light was stepping up its commitment. We have established Duquesne Light as one the leading companies in this region in proactively dealing with important social, human-services and economic-development issues. Our dollars, our people and our energy truly go to serving this community. At a time when the Pittsburgh region still is struggling, we are needed more than any other time in our company's 125-year history. This community needs a financially sound Duquesne Light.

We are part of the shrinking, few number of electric utilities whose headquarters are located in Pennsylvania. Having a company's headquarters located within the state is important for many reasons. One of the main benefits is retaining, and growing, jobs in the state. An important added benefit is the support work that goes to service providers like engineers, consultants and lawyers.

Another factor that sometimes goes unnoticed is the importance of having the executive team engaged in what is happening in the community where their business is headquartered. The level of commitment, interest and engagement this region receives from a company that is headquartered here is significantly higher than a company that is headquartered elsewhere. Having a successful rate case will benefit the Pittsburgh region by ensuring the future viability of a Pennsylvania-based good corporate citizen and its employees. This benefit cannot be maintained without a financially healthy Duquesne Light.

Q. In your four years as President of Duquesne Light, what has been your basic philosophy in managing this business?

A. We are doing what we do best -- focusing on the electric utility industry. A major effort has been a Back-to-Basics strategy that we implemented to re-establish the company's role as a premier provider of electric energy services and as a committed community partner.

We have a very long history of providing reliable, safe and efficient electric service to our customers in Allegheny and Beaver counties, and we intend to stay focused on that key objective. As noted earlier, extensive process improvements and the dedication of our employees have provided high levels of customer satisfaction and high levels of reliability, as measured by the PUC.

Our employees are fully engaged and committed to serving our customers. I greatly value the skill and effort they put forth every day of the year. Providing them a safe and satisfying work environment is critical to my management philosophy.

Providing value to our shareholders is another key component of that management philosophy. I am committed to providing shareholders a reasonable return on their investment while maintaining the highest standards of business ethics. I am advised that the Commission has discretion to set the cost of equity within the range of reasonableness established by the evidence in this proceeding, and that the Commission has used such discretion to reward or penalize companies based on management performance and service to customers. Given our extraordinary performance in serving our customers and our high level of community involvement, we have requested that the Commission set the return on equity on the high end of this range.

In addition, I strongly believe that our success as a company is directly connected to the success of the communities we serve. So whether we are investing our resources to ensure that our infrastructure meets the current and future electrical demands of Oakland, Downtown, Aliquippa, Beaver Falls and all of the other communities we serve, or investing in the development of talented students to help provide the leadership our region needs to grow and thrive, the goal is the same – to build strong and vibrant communities where we all can be successful.

Taking an active role in the neighborhoods where we live and work is the best way we know to demonstrate our loyalty and commitment to Pittsburgh and the entire southwestern Pennsylvania region. Those efforts have included sponsoring Pittsburgh traditions, such as Light Up Night and the Arts Festival; funding academic and development programs that help our children get ready for the jobs of tomorrow; and using the power of light to positively impact the region, such as the illumination of the Clemente Bridge and a key section of Penn Avenue downtown.

Our employees also are very active in the community – helping flood victims, food banks and youth groups, to name just a few ways. Employees volunteered nearly 6,000 hours at company-sponsored events in 2005, including helping low-income customers sign up for energy assistance and providing new winter coats for underserved youths. Every day, the company and its employees are investing their energy and resources to make powerful things happen that improve the quality of life for all who live and work in this region.

I also would like to emphatically state that in making this rate filing, we have not forgotten our low-income customers. As explained earlier, Duquesne Light has various universal services programs available to payment-troubled customers, including the Customer Assistance Program (CAP), Smart Comfort, the Customer Assistance & Referral Evaluation Service (CARES) program, Hardship Fund, and the Low-Income Home Energy Assistance Program (LIHEAP). In response to Governor Rendell's "Stay Warm" initiatives, the company introduced five new programs designed to extend the safety net for low-income and working poor families and seniors during the winter of 2005-06.

As part of our filing, we are proposing substantial increases in funding to assist low-income customers so that their monthly electric bills will remain essentially unchanged. Many of these customers are having difficulty meeting the obligations of all of their utility and energy requirements. We anticipate participation in our CAP program to increase substantially. The Commission is well aware of the success of our new Stay Warm programs, which are assisting not only low income but also working poor customers. I am pleased to recommend that we continue these Stay Warm programs.

Q: **Has your management been effective in implementing this philosophy?**

A: Yes, I believe so. Management has been very effective in navigating Duquesne Light through periods of great uncertainty and change, both in the electric utility industry and the region we serve. Our team has worked through some very difficult and challenging issues, such as electric restructuring, customer shopping, volatile wholesale markets for electricity, and loss of native load.

I would note, in particular, that Duquesne Light has been at the forefront of encouraging customer choice and in working with others to try to reap the benefits envisioned by restructuring. There is much more customer shopping in the company's service territory than in any other area of the state. Specifically, shopping represents approximately 53.5 percent of the total load in our service territory today.

Despite all that change and uncertainty, Duquesne Light's overall rate for a customer using POLR service is lower today than 15 years ago, while reliability and customer service have improved. We are recognized in the Pittsburgh region, by service organizations, our customers and elected officials, as a committed community partner. Each of these provide very good measures of management effectiveness. We have built on opportunities at our core, regulated utility business and continue to strengthen community and regulatory relationships. We need to ensure a continued safe, reliable supply of electricity for our customers and a safe and rewarding environment for our employees. And we need to do it at reasonable prices, especially for our low-income customers.

Q. **Finally, Mr. O'Brien, how can the Commission support industry restructuring and reliable and safe electric service for customers in Duquesne Light's territory?**

A. This case will be followed closely both within and outside the Commonwealth of Pennsylvania. This is an opportunity for the Commission to reconfirm that it recognizes – and supports – good utility management effectiveness and a strong utility infrastructure for customers. It offers a signal to businesses -- and to the financial community -- that Pennsylvania is looking to grow and prosper. I respectfully request that the Commission review Duquesne Light's filing carefully and approve rate relief sufficient to support a strong and healthy electric delivery service for Duquesne Light and its customers.

Q **Does this conclude your testimony?**

A Yes.

Morgan K. O'Brien

Education

B.S. Business Administration – Accounting, Robert Morris College, 1982
M.S. Taxation – Robert Morris College, 1984
Certified Public Accountant, 1984

Employment History

Duquesne Light Holdings, Inc. (DQE) – President and CEO since September 14, 2001. Chief Operating Officer from August 2000 to September 14, 2001. Executive Vice President – Corporate Development from January 2000 to August 2000. Vice President – Corporate Development from July 1999 to January 2000. Vice President, Controller and Treasurer from November 1998 to July 1999. Vice President and Controller from October 1997 to November 1998. Controller from October 1995 to October 1997. Assistant Controller from December 1993 to October 1995.

Duquesne Light Company – President and CEO from August 2003. Vice President – Finance from November 1998 to May 2000; Vice President – Finance, Treasurer & Controller in November 1998; Vice President & Controller from October 1997 to November 1998; Controller from September 1996 to October 1997; Controller and Principal Accounting Officer from October 1995 to April 1996; Assistant Controller from December 1993 to October 1995; Manager, Corporate Taxes from September 1991 to December 1993. Director since June 1999.

PNC Bank – Assistant Vice President, Taxes, 1990-1991.

Deloitte & Touche – Senior Manager, 1986-1990.

Coopers & Lybrand – Staff Accountant and Manager, 1982-1986.

Outside Affiliations

United Way of Allegheny County – Director
Catholic Charities of Pittsburgh – Director
Allegheny Conference on Community Development – Director
Edison Electric Institute – Director
Association of Edison Illuminating Companies – Director

Rate Schedule RS History
Average Monthly Cents/kWh at 600 kWh Usage

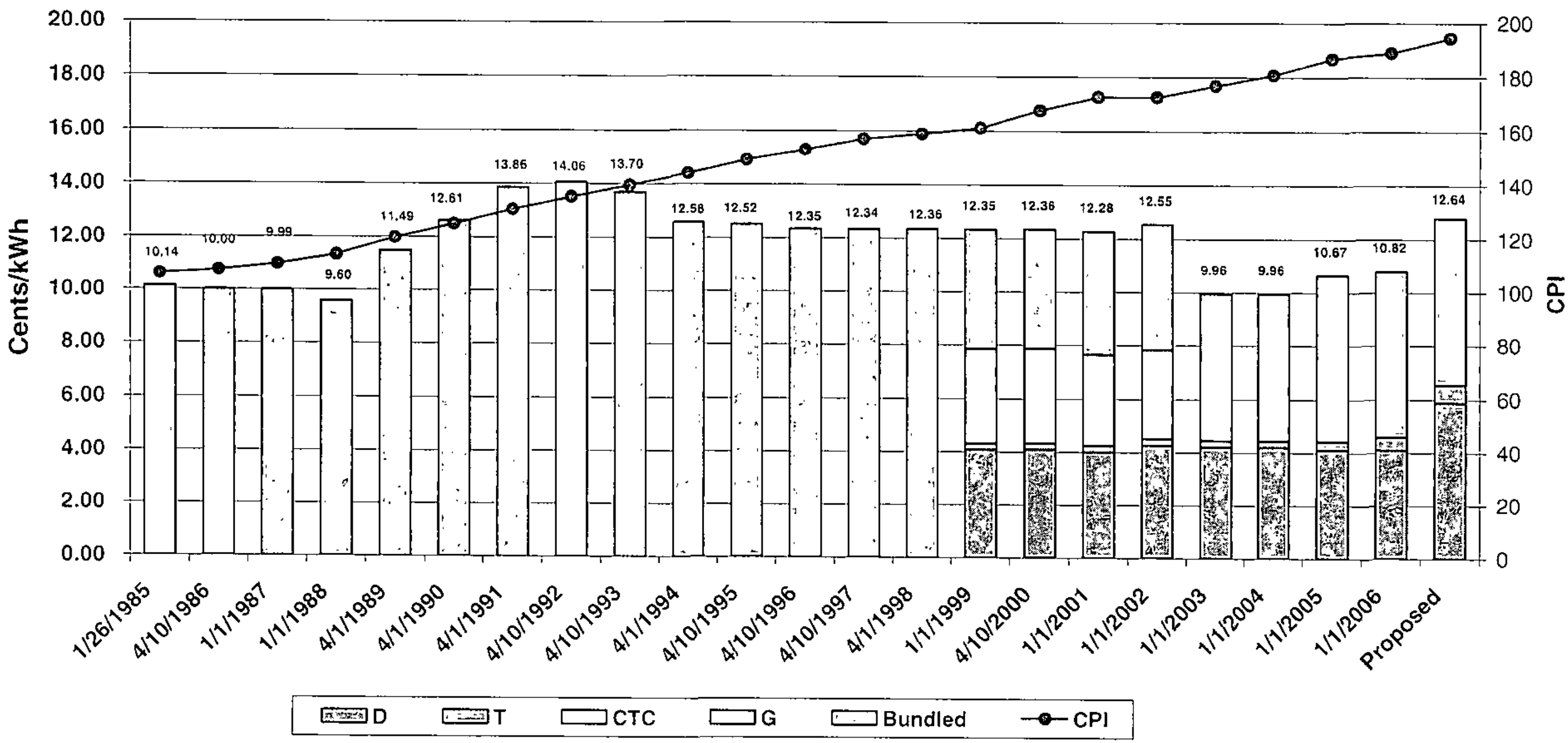

EXHIBIT MKO-2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

Statement No. 2

Direct Testimony of Susan S. Betta

DIRECT TESTIMONY OF SUSAN S. BETTA

Q. Please state your full name, business affiliation and address.

A. My name is Susan S. Betta. I am Controller of Duquesne Light Company ("Duquesne Light" or the "Company"). My business address is 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. Please describe your education and work experience.

A. I graduated from Franklin & Marshall College with a Bachelor of Arts in Accounting in 1991. I was employed with KPMG Peat Marwick for seven years and I was a Senior Manager when I left the firm.

I have been employed with Duquesne Light, or an affiliate of Duquesne Light for seven years. I spent the first year at an affiliate, DQE Financial, and have spent the past six years at Duquesne Light. I have been Controller at both Duquesne Light Holdings and Duquesne Light since August 2003. My current responsibilities include overseeing the accounting, reporting, budgeting and forecasting functions for Duquesne Light and Duquesne Light Holdings. Prior to August 2003, I served in various positions at the Company, including Assistant Controller of both Duquesne Light Holdings and Duquesne Light.

I am a Certified Public Accountant (CPA), and a member of both the Pennsylvania and American Institutes of Certified Public Accountants.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to describe and explain the Company's actual financial results for the Historic Test Year ended December 31, 2005, and to sponsor the budgeted financial results for the Future Test Year ending December 31, 2006. I will also provide an overview of the Company's presentation in this proceeding.

Q. Will there be other direct testimony provided by others?

A. Yes, there will be others providing testimony as part of this rate case. Please see Exhibit SSB-1 to my testimony for the listing of witnesses and subject matters to be addressed by them.

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes, I am. I am responsible for all of the recorded, as well as the budgeted amounts for the Company. As such, I am sponsoring all of the Company's financial statements, including income statements and balance sheets for the Historic Test Year of 2005. I am also sponsoring the Company's budget for the Future Test Year of 2006. With regard to the Commission's data filing requirements filed with this proceeding, I sponsor the financially-based responses, regarding measures of value and operating income. My name is at the top of each data filing requirement that I sponsor. In addition, I am co-sponsoring certain data filing requirements that were prepared with the assistance of William Fields, Vice President and Treasurer, relating to Duquesne Light's capital structure and cost of capital. Please see Exhibit SSB-2 to my testimony for the listing of data filing requirements that I am sponsoring.

Q. Did you prepare or supervise the preparation of exhibits presented in your testimony?

A. Yes, various exhibits were either prepared by me or under my direction. Duquesne Light's amounts shown in Exhibits B-1 to B-4 of the Historic Test Year of 2005 and the Future Test Year of 2006 reflect the Company's unadjusted financial results for the historic test year and budgeted financial results for the future test year, respectively.

Q. How are the Company's exhibits and data filing requirements organized?

A: The Data Filing Requirements are grouped together in sequential order, and they are named DLC Exhibit 1. DLC Exhibit 2 is comprised of all the Schedules for the Future Test Year of January 1, 2006 thru December 31, 2006. The Schedules include the Statement of Reasons (A Schedules), Financial and Capital Schedules (B Schedules), the Measure of Value or Rate Base Schedules (C Schedules) and Operating Income and Adjustment Schedules (D Schedules). DLC Exhibit 3 is the same information except it is for the Historic Test Year of January 1, 2005 thru December 31, 2005. The testimony has been grouped together in DLC Exhibit 4.

Q. Would you please provide a general description of the process used by the Company to determine its Pennsylvania jurisdictional revenue requirement?

A. The Company first developed the 2006 budget for construction expenditures, operating revenues, operating expenses and other elements. Next, each of the budget elements were analyzed to determine where pro forma adjustments would be required to reflect the 2006 test year under normalized conditions. The pro forma results for 2006 were used to prepare a jurisdictional separation to show the distribution plant, revenue and expenses for the Company's Pennsylvania jurisdiction only.

Q. Can you provide more detail on the overall process you described?

A. Yes, I can. I will use the operating budget as the example, but each of the measures of value, revenue and expense elements were determined following the same basic procedures. I was responsible for the development of the overall Duquesne Light budget for 2006. With regard to the operating expenses, because the Company does not budget expenses by Federal Energy Regulatory Commission ("FERC") account, as I will describe later, Mr. Robert O'Brien converted the Company's 2006 budget from the cost element format that we use, to a FERC format, which is presented on DLC Exhibit 2, Schedule B-4 and included on DLC Exhibit 2, Schedule D-2. Mr. Robert O'Brien, working with myself and other Company personnel, developed pro forma adjustments to the budget expenses by cost element, as shown on DLC Exhibit 2, Schedules D-7 through D-15. Each of these adjustments was distributed to the appropriate FERC account as shown on DLC Exhibit 2, Schedule D-3. These processes provided a total Duquesne Light pro forma level of expenses by FERC accounts for the test year 2006. Mr. Crowley then used these pro forma expenses in preparation of his Jurisdictional Separation Study, which is summarized on DLC Exhibit 2, Schedules C-1 and D-1.

Q. Was this process followed for each of the elements included in the Company's revenue requirement presentation?

A. Yes it was. For example, Mr. Robert O'Brien used the Company's budget for construction expenditures, construction closed to plant, plant retirements, depreciation expense, and other measures of value components as a starting point for pro forma adjustments and the resulting total Company pro forma measures of value was used by Mr. Crowley in his Jurisdictional Separation Study to determine the amounts for the Pennsylvania jurisdiction. A comparison of the total Company and Pennsylvania jurisdictional pro forma measure of value amounts is shown on DLC Exhibit 2, Schedule D-1, page 3. In addition, Mr. Robert O'Brien used the Company's budget calculation for depreciation expense and made pro forma adjustments to reflect the use of the year-end plant in service for 2006, the depreciation rates recommended by Mr. Spanos and pro forma plant additions to determine the total pro forma depreciation expense for the total Company, which Mr. Crowley used to determine the portion assigned to the Pennsylvania jurisdiction, pro forma for the test year.

Q. Please briefly describe the process used to calculate the pro forma jurisdictional measure of value, net operating income and required revenue increase for the Pennsylvania jurisdiction.

A. The process began with the Company's 2006 budget by cost elements, which are determined by total Company requirements and can be compared to budget and recorded amounts from prior years, which were then distributed to FERC accounts where necessary. Pro forma adjustments were made to the Company's budget amounts that allow for easy comparison for each adjustment. Finally, the total pro forma amounts were separated to the Pennsylvania jurisdictional level in one calculation as opposed to making this calculation for each budget element and each pro forma adjustment.

Q. Please describe how the Company's request for an increase in its electric distribution rates is supported by your data.

A. The requested increase is supported by the Company's budgeted financial data. In Schedule C-1 and D-1 of DLC Exhibit 2, I summarize the revenues, expenses, rate base, and deficiencies in revenue for the Future Test Year. Duquesne Light is requesting an overall distribution rate increase for the total Pennsylvania Jurisdiction of $143.7 million. Duquesne Light's capital structure is shown in DLC Exhibit 2, Schedule B-8, with the requested return on equity of 11.75% reflected on DLC Exhibit 2, Schedule B-9.

Q. Could you please describe the material presented on Schedules B-1 through B-4 and Schedules B-6 through B-8 of DLC Exhibits 2 and 3?

A. Schedules B-1 show the budgeted balance sheet of Duquesne Light as of December 31, 2006 and the actual balance sheet as of December 31, 2005. In accordance with FERC requirements, these balance sheets are presented using the equity method of accounting for subsidiary companies. Schedules B-2 are the statements of Duquesne Light's operating income for the year ended December 31, 2005 and budgeted for the year ending December 31, 2006. Details of actual and budgeted operating revenues are provided in Schedules B-3. Schedules B-4 provide the actual and budgeted operations and maintenance expenses of Duquesne Light by FERC account, including the major categories of expense, such as purchased power, transmission, distribution, customer accounts, customer service, and administrative and general expenses. Schedules B-6 and B-7 present the embedded cost of debt and preferred stock as of December 31, 2005 and 2006. The capital structure of Duquesne Light for the test year and prior years is shown on Schedules B-8.

Q. How was the information contained on Schedules B-1 through B-4 and Schedules B-6 through B-8 of DLC Exhibits 2 and 3 obtained?

A. All of the data shown in Schedules B-1 through B-4 and Schedules B-6 through B-8 were derived from either the books and records of Duquesne Light for the twelve months ended December 31, 2005 and prior, or the budget for Duquesne Light for the twelve months ending December 31, 2006.

Q. Could you explain your accounting system in place?

A. Duquesne Light maintains its accounting records on SSA Global's Masterpiece/Net general ledger package. The accounting records are maintained in accordance with the FERC's Uniform System of Accounts ("UsofA"). Financial statements for Duquesne Light are also prepared in accordance with generally accepted accounting principles ("GAAP").

Duquesne Light maintains its property, plant and equipment accounting records on the Power Plan Consultant's fully integrated asset accounting system, referred to as PAAM. The USofA requires that utilities record all construction and retirements of electric plant by means of work orders. The work order system must show the nature of each addition to, or retirement from, electric plant, the total cost thereof, and the plant account or accounts affected. Duquesne Light uses such a work order system, and under this system, an authorized work order is used for all capital work performed.

Q. How do you account for new plant put into service and associated retirements of existing plant?

A. Costs of new construction are tracked in the system by specific work order numbers. At the completion of each project, asset accounting receives reports from the operations personnel that show the date the project was placed in service and the listing of property constructed. Based on this information, the constructed property is placed in service and ultimately unitized, or charged to the correct units of property in the plant accounting system. At month end, journal entries are automatically generated and posted to the general ledger for these new in service dollars. In addition, the system calculates the allowance for funds used during construction ("AFUDC"), spreads overheads, calculates depreciation expense, processes unitized additions and processes plant retirements. The related journal entries are created and automatically posted to our general ledger.

Q. Please explain why Duquesne Light is requesting permission to recover AFUDC for plant held for future use?

A. Duquesne Light has not included plant held for future use in rate base in this proceeding because the plant is not currently providing service to customers. However, larger projects often have relatively long lead times from commencement to completion. While Duquesne Light is authorized to record AFUDC on the project expenditures once the project commences, Duquesne Light frequently must acquire land or land rights before construction begins. It is appropriate to allow Duquesne Light to record AFUDC on land acquired to provide future service and add such amount to rate base when the project is used to provide service to customers.

Q. Do you have an internal audit program?

A. Yes, Duquesne Light has an internal audit department, which implements its internal audit program. This department reports to the Audit Committee of the Board of Directors, as well as the Chief Executive Officer. They perform all internal work associated with ensuring the entities (Duquesne Light Holdings and Duquesne Light) are compliant with the requirements of Sarbanes-Oxley. Internal audit recently completed their Sarbanes-Oxley review for 2005, the result of which was an opinion of management that, as of December 31, 2005, the entities' internal control over financial reporting is effective based on criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Q. Do you have an external audit conducted periodically?

A. Yes, both Duquesne Light Holdings and Duquesne Light ("Companies") have external audits conducted annually by Deloitte & Touche LLP. Deloitte & Touche LLP recently completed their audits of the financial statements of the Companies for 2005, the results of which were unqualified opinions on the consolidated financial statements of the Companies as of December 31, 2005. In addition, Deloitte & Touche LLP recently completed their audits of management's assessment of the entities' internal control over financial reporting, as well as their own assessment of the same, and in both instances the result was an unqualified opinion.

Deloitte & Touche LLP also performs an annual audit of Duquesne Light's regulatory financial statements that are included in the FERC Form 1. Deloitte & Touche LLP normally completes this audit in April, and therefore they have not yet completed their audit of the December 31, 2005 regulatory financial statements. However, the audit performed on Duquesne Light's regulatory financial statements included in the December 31, 2004 FERC Form 1 resulted in an unqualified opinion, which I also expect to receive when the 2005 audit is completed.

In addition to the annual audits performed by Deloitte & Touche LLP, both the FERC and the Pennsylvania Public Utility Commission ("Commission") have performed periodic audits of Duquesne Light.

Q. Have any major accounting changes occurred during the past several years?

A. There have been a number of accounting changes that have occurred over the past several years as required by new pronouncements that have been issued by the Financial Accounting Standards Board ("FASB") and others. The Company has implemented these new standards and pronouncements in order to maintain their accounting records in accordance with accounting principles generally accepted in the United States of America. Please refer to data filing requirement II-D-12 that outlines the accounting changes that have occurred since our last rate case filing.

Q. Are you responsible for the budget process for the Future Test Year?

A. Yes, I am responsible for the oversight of the budgeting process for Duquesne Light. The budget department reports to me, and accumulates all of the budget data from the various sources within the company to prepare the full income statement budget for the Company. We project the budgeted year-end balance sheet for Duquesne Light, as well as budgeted cash flows for the year.

Q. Please describe the Company's budget process.

A. Each year there is an annual planning process that begins in mid-to-late August. The budget process involves various employees throughout the organization. Retail sales of electricity and purchased power expense are budgeted by our forecasting and economic analysis department, while other revenues are budgeted by our operations group for items such as rental of electric property, etc. Operations and maintenance expenses are budgeted by the individual cost center managers within the Company. Human resources is contacted for input on salary increase assumptions and fringe benefit costs. The information is summarized for the Company by our cost element detail, which shows total labor, fringes, outside services, etc. See Exhibit SSB-3 to my testimony which describes the cost elements we use to budget, and Exhibit SSB-4 for a listing of the individual cost centers within Duquesne Light. The tax department assists in budgeting the taxes other than income taxes, as well as income tax expense, while asset accounting prepares the budget for depreciation and amortization expense, as well as the AFUDC, based in part on information received from the operations group for expected capital expenditures. Our treasury department assists in budgeting the interest expense and preferred dividends we expect to incur, as well as the amortization of debt discounts, premiums, etc.

Q. How were the budgeted retail revenues derived?

A. Mr. Wreschnig prepares a detailed budget for retail revenues. Please see his testimony in Statement No. 4 for details regarding this budget process.

Q. How were the other operating revenues budgeted?

A. Our operations group provides the budgeted amounts for items such as rental of electric property, transmission, and customer related miscellaneous and commitment revenue. The remainder of the categories is determined based on historical amounts adjusted for known changes or initiatives being undertaken. These amounts include late payment charges, returned check fees and reconnect fees.

Q. How were purchased power expenses determined?

A. The expenses in the purchased power category represent the cost to purchase power, and include purchases to meet Duquesne Light's Provider of Last Resort ("POLR") requirements for our customers. However, power costs are not included in the determination of the transmission or distribution revenue requirements in this filing.

Q. How do cost center managers prepare their budgets for operations and maintenance expenses?

A. Cost center managers are provided a budget template to fill out and submit to the budget manager, who reports directly to me. This template identifies the cost elements that the company uses to budget, and each cost center manager completes this template. They use their knowledge of the employees in their cost center, related salaries and guidance provided in the template directions on management salary increases to determine the budgeted wages. During the year, these cost center managers receive monthly reports of their actual expenses versus budgeted expenses, and these reports help them to budget for the following year by identifying the various other costs that they incur during the year, such as outside consultants, materials and supplies, etc. In addition, these reports highlight any variances in the prior year budget that should be addressed in the current year's budgeting process.

Q. Do these cost center managers budget for costs that are expected to be capitalized, as well as expensed?

A. Yes they do. The operations group is provided with budget templates including all of the cost elements that are budgeted for capital. They use the knowledge of the employees in their cost center and related salaries, the capital projects that have been identified for the next year for them, as well as the typical costs that they incur on an annual basis. During the year, these cost center managers receive monthly reports of the actual capital work that they have performed to help them plan their work activities.

Q. Do you have an administrative services agreement that allows Duquesne Light employees to provide services to affiliates?

A. Yes, Duquesne Light has an administrative services agreement in place with its affiliates. This agreement has been filed with the Commission, and is updated periodically as necessary. This agreement is explained and included as part of the response to data filing requirement II-D-8.

Q. Do you consider work that Duquesne Light employees may be doing for affiliates in the budgeting process?

A. Yes, cost center managers provide information regarding any work that their department is doing for any affiliate. The individual employee is to be listed along with an estimate of the percentage of their time to be spent on behalf of each affiliate during the year. An allocation of all employees performing work is prepared. The cost charged to any affiliate includes the employee's salary and related benefits. The cost center managers also separately list any other costs that should be allocated to an affiliate (for example, computer software and hardware costs, cash management fees). A total of all of the allocation amounts is calculated and is included in the budget process as a reduction in expense, which we refer to as subsidiary reimbursements.

Q. Does Duquesne Light share office space with its affiliates, and are the affiliates charged for this space?

A. Yes, Duquesne Light shares office space with its affiliates and those affiliates are charged for this space. The Company has entered into a lease agreement for office space located at 411 Seventh Avenue. Duquesne Light subsequently entered into subleases with several of its affiliated companies, and its parent company, Duquesne Light Holdings, to sublease space to them. These subleases have been filed with the Commission, and are included as an attachment to data filing requirement II-D-8. The facilities department monitors the office space and periodically provides the budgeting department with floor plans detailing where each Duquesne Light cost center or affiliate is located on each floor and the square footage occupied by each. The budget department uses the square footage to develop an allocation of each floor's rented area to cover each floor's common space (for example, elevator lobby, hallways, restrooms etc) and then a building common allocation is determined for the building lobby and a floor that is partially dedicated to conference and training rooms which can be reserved by all Duquesne Light and affiliate employees.

Q. How do you budget for fringe benefits provided to employees?

A. This process varies, depending on the type of fringe benefits, and will be described more fully below. However, most benefits are provided to employees of Duquesne Light as well as its affiliates, and therefore the initial step is in determining the total cost expected to be incurred. Employees from human resources and benefits review each of the health coverage plan costs for the current year and then the budget is developed taking into consideration the present number of eligible employees, changes in the numbers of eligible employees, any changes in employee contribution levels and estimated cost increases. Once the total has been established, the percentage of that total cost that is applicable to just Duquesne Light employees is determined, in part, by reviewing the previous year.

Q. Is the Company self-insured for any employee benefits, and if so, how is the budget for those benefits estimated?

A. Yes, Duquesne Light is self insured for medical coverage and provides employees with a choice of three options that are administered by Highmark Blue Cross Blue Shield under a national Preferred Provider Organization. The budget estimates are developed based on the previous year's claim costs with adjustments for anticipated changes in the number of eligible employees, employee contribution levels and cost increases based on healthcare industry outlook. Duquesne Light does have stop-loss insurance coverage for claims that are over $500,000 per incident.

Q. How has Duquesne Light tried to minimize healthcare coverage costs?

A. Over the past several years, Duquesne Light has taken various steps to mitigate the high cost of healthcare such as consolidating the union and non-union employees to the same plan and increasing employee contribution levels.

Q. Do you then allocate the cost of fringe benefits to both capital jobs and expense?

A. Yes we do. This allocation is calculated based on the amount of expected labor costs to be incurred based on the information submitted by the individual cost center managers during the annual budgeting process that will be charged to operation and maintenance expense or to capital. The result is used to allocate the benefit costs so that the benefit costs are proportionate to the labor.

Q. What types of benefits do you provide to Duquesne Light employees?

A. Benefits for 2006 include medical and dental coverage, flexible spending accounts, life insurance, optional life and accident insurance, business travel insurance, disability benefits, an employee assistance program and tuition reimbursement. In addition, we maintain several retirement plans to provide pensions for all eligible full-time employees. Upon retirement, an eligible employee receives a monthly pension based on his or her length of service and compensation. The cost of funding the pension plans is determined by the unit credit actuarial cost method, and at the end of each year is projected for the next five years. Our policy is to budget using the actuarially determined net periodic pension cost.

Q. Are you claiming the actuarially determined net periodic pension cost for pensions in this rate proceeding?

A. No, we are not. We are requesting recovery of the annual contributions that we plan to make to the pension plans. These contributions consider the minimum contribution amount required and the maximum tax-deductible contribution allowed which are determined annually, in accordance with Section 412 and 404, respectively, of the Internal Revenue Code and the criteria required to be used to determine these contributions are different from the criteria required to be used to determine pension costs under SFAS No. 87. During 2006, we have made contributions totaling $20 million to the pension plans and plan to continue to fund the pension plans at this level into the future. Therefore the expense claim for pensions in this proceeding is based on pension plan contributions at the $20 million level, less the amount that will be capitalized and included in rate base.

Q. In future years, when does the Company expect to make these annual contributions to the pension plan trust?

A. The Company plans to make these contributions early in the year, and the actuarial projections of the future cost of the Company's pension benefits has been performed on this basis.

Q. Please explain the proposed future accounting treatment with regard to pensions.

A. The Company is required to accrue an amount for pensions on its books of account each year determined in accordance with Statement of Financial Accounting Standards ("SFAS") 87. While the procedures used to determine the annual SFAS 87 accrual and procedures used by the Company's actuaries are similar, the annual accrual will likely differ from the pension contribution on a year-to-year basis. However, over extended periods, the total contributions must be essentially the same as the sum of the annual accruals. For this reason, the Company requests that the Commission authorize the Company to record annually the difference between the contribution to the pension trust and the annual accrual as either a regulatory asset or liability. These amounts will then be reversed over time in the future.

Q. Is there a specific provision that should be included in the Commission's final order related to pensions?

A. Yes, I have provided the provision in Exhibit SSB-5.

Q. What other postretirement benefits ("OPEBs") does Duquesne Light provide to its employees?

A. In addition to pension benefits, the Company provides certain healthcare benefits and life insurance for some retired employees. The life insurance plan is non-contributory. Retirees participating in the health care plan do make contributions, which may be adjusted annually. Health care benefits terminate when a retiree reaches age 65. We currently fund actual expenditures for obligations under the plans on a "pay-as-you-go" basis. However, on our books of account, the Company accrues the actuarially determined costs of the aforementioned postretirement benefits over the period from the date of hire until the date the employee becomes fully eligible for benefits.

Q. Are you claiming the actuarially determined net periodic cost for postretirement benefits in this rate proceeding?

A. Yes we are. In accordance with the Commission's Policy Statement implementing SFAS 106, 52 Pa. Code § 69.351b(4), Duquesne Light is in the process of establishing trusts for our postretirement benefits. The policy statement requires that any amounts recovered that exceed the "pay-as-you-go" amount must be deposited in the trusts. Commencing in 2007, Duquesne will deposit the full ratemaking allowance into the trusts and pay amounts for benefits out of the trust, with the result that any amount recovered in excess of actual expenditures will accumulate in the trusts.

Q. Is Duquesne Light requesting that the difference between the rate allowance and the annual OPEB expense accrual be deferred as a regulatory asset or liability?

A. Yes. Any difference between the annual book accrual and the ratemaking allowance will be deferred and amortized over a reasonable period as an increase or decrease to the rate allowance for OPEBs in the next rate proceeding. This procedure is consistent with the Commission's requirement that the rate allowance be placed in the trust without regard to the actual annual accrual. It is also consistent with the Commission's treatment of OPEBs for other utilities.

Q. Is there specific language that should be included in the Commission's final order on the subject of OPEBs?

A. Yes, I have provided the proposed provision in Exhibit SSB-5.

Q. How are taxes other than income taxes budgeted?

A. Our tax department performs a calculation of each type of taxes other than income taxes. The expected gross receipts tax is based on estimated taxable revenues multiplied by the expected tax rate, currently 59 mills. The capital stock tax is budgeted based on the statutory formula of capital stock value multiplied by the expected tax rate, currently 4.99 mills. The Public Utility Realty Tax ("PURTA") and other real estate taxes are budgeted based on the amounts paid in the prior year, adjusted for any major additions or sales of real estate property. Payroll taxes are budgeted based on the expected tax rates applied against the estimated payroll costs to be incurred. Miscellaneous taxes are budgeted based on the expected amounts expected to be incurred for items such as business privilege tax, as well as sales and use tax audits.

Q. Please describe how income taxes are calculated

A. The tax department uses budgeted pre-tax book income to calculate income taxes. The current federal tax expense is reduced by the annual amortization of deferred investment tax credit.

Q. How do you budget for depreciation expense?

A. Our asset accounting department prepares the budget for depreciation and amortization expense based on current property, plant and equipment and anticipated capital expenditures, including estimated in-service dates, for the coming year.

Q. Please describe how interest expense and the amortization of debt discounts, etc. are calculated for the budget.

A. Our treasury department calculates the interest and preferred dividend costs by multiplying the outstanding debt and preferred stock balances by the applicable interest and dividend rates. Annual amortization expense is determined by dividing the original unamortized balance of costs and premiums by the original life of the debt issuance. New financings are modeled into the budget when capital requirements exceed cash sources. The expected costs for these new financings, such as the expected interest rates and costs to be incurred, are provided by outside advisors.

Q. What is the review process for the Company's budget?

A. The budget information that is compiled is reviewed and evaluated thoroughly by all levels of the Company to ensure that the budget reflects what the Company expects to incur for the year. Inquiries and modifications are common throughout the budget process. The budget is then approved by management and reviewed with the Board of Directors.

Q. Does the Company typically prepare its budget by FERC account?

A. No, we prepare the budget for Duquesne Light by cost element detail as this level of detail facilitates the reviews by our cost center managers and assists them in estimating their expenses for budgeting purposes. To satisfy the requirements for this rate filing, our cost element budget was allocated to FERC accounts. Certain cost element budget amounts could be specifically assigned to certain FERC accounts as they are easily identifiable to those accounts. For other cost element budget amounts, an allocation to FERC accounts was performed based on the same relationship to the total as the actual costs shown for the Historic Test Year operating and maintenance expenditures, which were reported by both cost element and FERC account. Once this allocation was performed, the results were reviewed to ensure they appeared reasonable, and adjustments were made as necessary to reflect expected variances. This process is more fully described in the testimony of Mr. Robert O'Brien.

Q. How do you monitor the budget against actual expenditures?

A. The budgeted versus actual results are monitored on a monthly basis by cost element when the monthly accounting close is completed. Explanations for deviations from the budget are obtained from the appropriate personnel.

Q. Has the operating budget provided a reasonable estimate of actual expenditures?

A. Yes, over the past three years the total operations and maintenance budget has closely approximated the actual costs incurred.

Q. Are you aware of the requirement that a comparison of actual to budget data is to be supplied quarterly when you utilize a Future Test Year?

A. Yes, Exhibit SSB-6 has been provided showing a breakdown of revenues and expenses for the Future Test Year into calendar quarters for 2006. We will provide quarterly comparisons of actual results to the budget as shown as the actual data for each quarter becomes available.

Q. Have you made any adjustments in your Future Test Year to account for known and measurable changes?

A. Yes we have. Mr. Robert O'Brien is sponsoring all the adjustments that are known and measurable and his testimony will address those items specifically.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SUBJECT MATTER	WITNESS	STATEMENT
Overall Policy	Morgan O'Brien	1
Financial Operations Budget for Future Test Year Miscellaneous	Susan Betta	2
Capital Budget	Jeff Coward	3
Revenue and Sales Forecast Load Research	Stephen Wreschnig	4
Taxes	Mauro Macioce	5
Rate of Return Capital Structure Cost of Debt Cost of Equity	Paul Moul	6
Financial Markets Investor Perspective Cost of Equity	Julie Cannell	7
Pro Forma Adjustments Plant Accumulated Depreciation Working Capital Revenue Adjustments Expense Adjustments	Robert O'Brien	8
Jurisdictional Separation/Revenue Deficiency PJM Transmission Expense	Larry Crowley	9
Depreciation Reserve Service Life Study Depreciation Rates	John Spanos	10
Cost of Service Cost Allocation Study	Howard Gorman	11

SUBJECT MATTER	**WITNESS**	**STATEMENT**
Rate Design Class Revenue Allocation Bill Calculation Proof of Revenue Distribution System Improvement Charge Transmission Tracker	William Pfrommer	12
Customer Programs CAP Other Universal Service Funds	Michele Sandoe	13
Tariff Schedules/Changes	Nancy Krajovic	14

CITATION	DESCRIPTION
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53.53 I A	**Summary of Filing**
53.53–A-3	Summary tables
53.53-A-4	Generation Plant additions
53.53 I B	**General Description of Operations**
53.53-B-1	Corporate History
53.53-B-2	Description of Property/System Operations
53.53 II	**PRIMARY STATEMENTS OF RATE BASE & OPERATING INCOME**
53.53 II A	**Rate Base**
53.53-II-A-1	Test Year rate base and rates of return – future
53.53-II-A-2	Test year rate base and rates of return – historic
53.53-II-A-3	Generation cost information
53.53 II B	**Rate Base Supporting Schedules**
53.53-II-B-1	Plant held for Future Use
53.53-II-B-2	Construction Work In Progress
53.53-II-B-3	Claim for materials and supplies
53.53-II-B-5	Compensating Bank balances
53.53-II-B-6	Additional Items in Measure Of Value
53.53 II C	**Operating Income Statement**
53.53-II-C-1	*Budgeted Income Statement Detail*
53.53-II-C-2	Similar schedule historic test year

CITATION	DESCRIPTION
53.53 II D	**Income Statement Supporting Schedules**
53.53-II-D-1	Schedule of revenues & expenses for FTY& HTY & variance explanation
53.53-II-D-2	Summary of test year adjustments
53.53-II-D-3	Nonrecurring & extraordinary items
53.53-II-D-4	Extraordinary property losses
53.53-II-D-5	Reserve for uncollectible
53.53-II-D-6	Claim for rate case expense
53.53-II-D-7	*Components of Expenses*

53.53-II-D-8	Affiliate charges for FTY and HTY
53.53-II-D-9	Social and Service organization memberships
53.53-II-D-10	Payroll & Benefit Data
53.53-II-D-11	Leasing costs and method for calculating
53.53-II-D-12	Past & anticipated accounting changes & internal/external audit reports
53.53-II-D-13	Gross salvage, CR, net salvage for 4 previous years
53.53-II-D-26	Other items
53.53 II E	**Budgeted Data**
53.53-II-E-1	Copies of budgets & explanation of process
53.53-II-E-2	Budgets (operating & capital) for 3 years
53.53-III	**RATE OF RETURN**
53.53-III-A	**Claimed Rate of Return**
53.53-III-A-1	Capital structure, derivation of costs & changes for previous period
53.53-III-A-2	Same for 2 previous periods
53.53-III-B	**Embedded Cost of Long-term Debt**
53.53-III-B-1	Detailed schedule of cost of LTD
53.53-III-B-2	Claim for true or economic cost if any
53.53-III-B-3	Debt Information
53.53-III-B-4	Other short-term debt information
53.53-III-B-5	LTD reacquisition information by issue for company & parent
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53.53-III-C-1	Detailed schedule of cost of preferred stock
53.53-III-D	**Cost of Common Equity**
53.53-III-D-2	Stock dividends, splits, etc for 2 years
53.53-III-D-3	Common stock issuances for last 2 years
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–3.53-III-E-1	Reasons for claim if based on consolidated capital structure
53.53-III-E-2	Capital structure for parent for lat 2 years
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53.53-III-E-4	Organizational chart
53.53-III-F	**General Financial Data**
53.53-III-F-1	Quarterly and annual reports
53.53-III-F-2	Projected capital requirements & sources for FTY & 3 projected years

53.53-III-F-3	Coverage requirements
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53.53-V-A	**Adjusted original cost with accumulated depreciation**
53.53-V-A-1	Schedule of plant in service by function
53.53-V-A-2	*Book reserve versus calculated reserve*
53.53-V-A-3	Supporting schedules
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53.53-VI-a	Balance sheet - 3 years
53.53-VI-b	Income Statement - 3 years
53.53-VI-c	Plant in Service - 3 years
53.53-VI-d	Accumulated depreciation - 3 years

Cost Elements

Cost Element	Description
10	Labor
11	Overtime Labor
14	Rent
15	Incentive Compensation
20	Stores Issues and Returns
23	Materials Purchased
24	Utilities
30	Transportation
40	Telephone Services
42	Other Rent
43	Software Leases
44	Insurance
45	Mobile Phone / Pager Costs
50	Healthcare & Misc. Benefits
51	Employee Expenses
57	Hardware Maintenance
59	Outside Services
60	Pension Costs
61	Transmission Expenses
65	Uncollectible Accounts
67	Reimbursements
71	Temporary Labor
72	Mailing Costs
75	Memberships / Dues
76	Business Meals
88	Subsidiary Reimbursements
99	Miscellaneous

Group	Cost Center	Description
Treasury	050	Shareholder Relations
	007/405	Insurance Department
	430	Vice President and Treasurer
	435	Treasury Operations
	436	Investor Relations
	437	Pension Administration
	438	Corporate Finance
Finance	400	Sr. Vice President and Chief Financial Officer
	406	Vice President Finance
	407	Tax Department
Controller	409	Asset Accounting
	410	Controller & Reporting
	422	Accounts Payable
	423	Payroll
	440	Corporate Accounting
Corporate Communications	018	Community Relations
	019	Media Relations
	031	Marketing Communications
	032	Corporate Communications
Human Resources	301	Human Resources & Benefits
	302	Employee & Labor Relations
	512	HRIS
	516	Compensation & Benefits
Facilities, Environmental & Security	530	Facilities Management
	705	Environmental
	848	Security
Information Technology	445	Enterprise Applications
	540	IT- Director
	546	Enterprise Infrastructure
	549	Voice & Data Communications
Customer Service	490	Customer Resources
	491	Call Center
	492	PUC & Quality

Asset Management & Engineering	805	Asset Management & Engineering
	810	Asset Management
	815	Real Estate
	820	Engineering
	825	Technical Services & ERS
Revenue Cycle Services	493	Credit & Collections
	494	Field Services
	495	Universal Services
	496	Customer Billing
	497	Payment Processing
	498	Metering
	499	Meter Reading
Work Management	830	Work Management
	831	Backshift
	832	Penn Hills - Maintenance & Service
	833	McKeesport - Maintenance & Service
	834	Highland - Maintenance & Service
	835	Curry - Maintenance & Service
	838	Raccoon - Maintenance & Service
	839	Edison - Maintenance & Service
	844	Findlay - Maintenance & Service
	845	Preble - Maintenance & Service
	846	Legionville - Maintenance & Service
	847	Major Construction & Account Management
Underground Operations	840	Control Room
	849	Outage Coordination & Field Support
	855	Underground
Operations Services	502	Vegetation Management
	503	Construction Management
	560	Clerical
	836	Street Lighting - City of Pittsburgh
	572/582	Transportation
	586	Supply Chain, Shops and Testing
Operations Office	800	Sr. Vice President and Chief Operations Officer
Transmission	850	Transmission Business
Administrative	300	Sr. Vice President and Chief Administrative Officer
	006	Legal
	470	Rates & Regulatory Affairs
	040	Corporate Compliance / Corporate Secretary
	311	Training & Safety
	003	Audit Services
	321	Performance Management
	449	Corporate Development

Pension Language:

The Company has calculated and accrued on its books of account its pension liability incurred for its present and former employees under the terms of SFAS No. 87. The Company makes cash contributions into qualified trusts to fund its pensions. The minimum contribution amount required and the maximum tax-deductible contribution allowed are determined annually, in accordance with Section 412 and 404, respectively, of the Internal Revenue Code and the criteria required to be used to determine these contributions are different from the criteria required to be used to determine pension costs under SFAS No. 87. For financial reporting purposes effective January 1, 2007, the Company will record the amount accrued in excess of the cash contribution as a regulatory (deferred) asset in accordance with SFAS No. 71 until the cash amount equals or exceeds the accrual. When the cash contribution is different from the accrual amount, the Company will correspondingly record or adjust the regulatory (deferred) asset or regulatory liability. For ratemaking purposes in the future, the Company will continue to use cash contributions plus pension administrative costs as the basis for its ratemaking claim for pension expense.

OPEB Language:

The Company will account for and fund OPEBs through irrevocable trusts and/or accounts, into which will be deposited the full amount of payments calculated by the Company's actuary pursuant to SFAS 106. Retiree OPEBs and administrative costs of maintaining the trusts and/or accounts will be paid from amounts deposited. The Company will account for the difference between the net periodic postretirement benefit expense determined annually by the actuary in accordance with SFAS 106 and the amount of SFAS 106 postretirement benefit expense included in rates. That difference will be recorded as a regulatory asset or liability and will be expensed or credited in future rate proceedings in determining net periodic OPEB expenses.

DUQUESNE LIGHT COMPANY
STATEMENT OF INCOME
2006 Operating Budget

Account	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total 2006
UTILITY OPERATING INCOME					
Operating Revenues (400)	179,662,221	166,492,045	211,362,406	167,789,512	725,306,184
Operating Expenses					
Purchased Power	88,403,848	81,071,124	106,923,389	82,116,311	358,514,672
Operating Expenses (401,402)	*37,973,869*	*36,788,696*	*38,754,546*	*39,804,739*	*153,321,850*
Depreciation Expense (403)	15,820,162	15,820,162	15,820,162	15,820,162	63,280,648
Amort. & Depl Of Utility Plant (404-405)	824,418	824,418	824,418	824,418	3,297,672
Regulatory Debits (Credits), net (407.3,407.4)	2,324,040	1,962,726	2,654,208	2,078,236	9,019,210
Taxes Other Than Income Taxes (408.1)	12,681,975	11,651,187	14,072,935	11,498,214	49,904,311
Income Taxes - Federal (409.1)	392,673	(670,570)	3,655,492	(1,808,489)	1,569,105
Income Taxes - Other (409.1)	*124,519*	*(212,642)*	*1,159,184*	*(573,485)*	*497,576*
Provision for Deferred Income Taxes, net (410.1,411.1)	4,171,290	4,171,290	4,171,290	4,171,297	16,685,167
Investment Tax Credit, net	(363,673)	(363,673)	(363,673)	(363,673)	(1,454,691)
Total Utility Operating Expenses	162,363,121	151,042,718	187,671,951	153,567,730	654,635,520
Net Utility Operating Income	17,309,100	15,449,327	23,690,455	14,221,782	70,670,664
OTHER INCOME AND DEDUCTIONS					
Other Income					
Equity in Earnings of Subsidiary Companies (418.1)	55,250	55,250	55,250	55,250	221,000
Interest and Dividend Income (419)	380,721	379,824	378,918	378,005	1,517,466
Allowance for Other Funds Used During Construction (419.1)	291,652	291,652	291,652	291,652	1,166,606
Miscellaneous Nonoperating Income (421)	358,410	358,410	358,410	358,421	1,433,651
Gain on Disposition of Property (421.1)	-	-	-	-	-
Total Other Income	1,086,032	1,085,135	1,084,229	1,083,327	4,338,723
Other Income Deductions					
Loss on Disposition of Property (421.2)					
Donations (426.1)	447,000	368,000	222,000	328,000	1,365,000
Penalties (426.3)	-	-	-	-	-
Exp for Certain Civic, Political, & Related Activities (426.4)	105,986	106,986	106,986	102,986	422,944
Other Deductions (426.5)	360,216	445,996	201,186	247,339	1,254,737
Total Other Income Deductions	913,202	920,982	530,172	678,325	3,042,681
Taxes Applicable to Other Income and Deductions					
Income Taxes - Federal (409.2)	(78,127)	(79,702)	(7,874)	(35,584)	(201,287)
Income Taxes - Other (409.2)	272,709	272,210	294,987	265,224	1,105,130
Total Taxes on Other Inc. and Ded.	194,582	192,508	287,113	229,640	903,843
Net Other Income and Deductions	(21,752)	(28,355)	266,944	175,362	392,199
Interest Charges					
Interest on Long-Term Debt (427)	9,534,895	9,546,171	9,557,448	9,975,938	38,614,452
Amortization of Debt Disc. and Expense (428)	910,170	910,170	910,170	913,922	3,644,432
Amortization of Premium on Debt - Credit (429)	-	-	-	-	-
Amortization of Gain on Reacquired Debt - Credit (429.1)	(29,917)	(29,917)	(29,917)	(29,917)	(119,667)
Interest on Debt to Assoc. Companies (430)	-	-	-	-	-
Other Interest Expense (431)	99,684	203,684	398,753	653,259	1,355,380
Allowance for Borrowed Funds Used During Construction-Cr. (432)	(178,999)	(178,999)	(178,999)	(178,999)	(715,996)
Net Interest Charges	10,335,833	10,451,109	10,657,455	11,334,203	42,778,601
Net Income	$ 6,951,515	$ 4,969,863	$ 13,299,944	$ 3,062,941	$ 28,284,262

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

RECEIVED

APR - 7 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Duquesne Light Company

Statement No. 3

Direct Testimony of Jeffrey L. Coward

DIRECT TESTIMONY OF JEFFREY L. COWARD

Q. Please state your full name and business address.

A. My name is Jeffrey L. Coward. My business address is 2841 New Beaver Avenue, Pittsburgh Pennsylvania 15233.

Q. What is your position at Duquesne Light Company?

A. I am Director of Asset Management and Engineering, a department in the Operations and Customer Services organization of Duquesne Light Company ("Duquesne Light" or the "Company").

Q. Please summarize your responsibilities and duties as they relate to this testimony.

A. I am responsible for evaluating the ability of Duquesne Light to meet the needs of our customers and to develop maintenance programs and capital addition plans needed to ensure that Duquesne Light's infrastructure continues to provide safe, reliable, responsive, and efficient service to our customers. My duties include establishing engineering standards and performance criteria for the Duquesne Light electric system, analyzing the electric system performance and condition, predicting changes in system performance and condition, and selecting and prioritizing maintenance expenses and capital additions.

Q. Please provide your educational background and describe your professional experience.

A. I have been employed by Duquesne Light since 1983 and have progressed through numerous engineering and customer service positions directly related to understanding electrical system requirements and meeting customer's needs, and through multiple management functions related to planning system infrastructure repairs, replacements, and reinforcements necessary to meet the customer's needs and regulatory requirements.

From 1983 through 1987 I progressed through increasingly responsible engineering positions working on transmission and distribution standards, operating procedures, supervision of Transmission and Distribution technicians, design of overhead distribution and underground network systems to provide service to new customers, design of complex engineering assignments such as new overhead and underground distribution circuits and major extensions or revisions to existing distribution circuits.

From 1987 to 1999 I progressed through increasingly responsible customer service and account management positions working to support the needs of Commercial, Industrial and Residential customers. My duties included overseeing the timely service connections of customers to Duquesne Light facilities, while acting as a liaison between the customer's design agencies and the Company's engineering and construction departments.

I joined the Asset Management Department in 1999, serving as Manager, System Planning and Analysis responsible for leading the long term technical planning for the Company's delivery system infrastructure, and as Manager, Asset Management, responsible for directing the strategic and operational planning required to develop and monitor the Company's annual delivery system work plan. I was appointed to my current position, Director of Asset Management and Engineering, in 2001.

I received a Bachelor of Science degree in Electrical Engineering from Grove City College in Grove City, Pennsylvania in 1983. I regularly participate in electric utility industry seminars, conferences, and forums to stay current with industry practices regarding the planning, capital addition decision-making, and other elements of electric utility asset management.

Q. What is the purpose of your direct testimony?

A. My purpose is to describe and explain Duquesne Light's capital additions during the historic and future test years. Specifically, my testimony: (1) provides a brief description of Duquesne Light's electric delivery system, (2) explains Duquesne Light's planning process to ensure its electric system continues to meet the needs of its customers and why the Company is making more capital additions during the historic and future test year periods than in prior years, (3) explains the process followed by Duquesne Light to determine which capital additions are necessary and when they must be added, (4) explains the primary reasons why Duquesne Light makes capital additions, and (5) describes major capital additions for 2006.

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes. I am sponsoring Exhibit JLC-1, which I prepared and which provides the basis for estimates of electric plant additions and retirements reflected in the future test year. It is a summary of Duquesne Light's 2005 – 2007 electric utility capital budget that includes additions for the historic and future test years.

Q. Could you briefly describe Duquesne Light's electric system?

A. Duquesne Light provides electric service to approximately 587,000 customers located substantially in Allegheny and Beaver counties (including the city of Pittsburgh), a service territory of approximately 800 square miles. Duquesne Light delivers electricity from a variety of generation sources through a complex transmission and distribution system at the voltage and in the quantity required by our customers. The system includes approximately 45,000 miles of power lines, over 500 substations, approximately 200,000 utility poles, and over 100,000 transformers.

The transmission system consists of a network of 345 kV, 138 kV, and 69 kV transmission lines that supply a series of substations. These lines move bulk power from the various sources of supply, which sources Duquesne Light does not own, to Duquesne Light's service territory to meet our customers' demands. These lines are the most reliable form of power line and are the most electrically efficient. They enable the movement of large quantities of bulk power with minimal energy loss or voltage drop. These transmission lines supply power to various types of substations within our service territory. Substation transformers then convert the transmission voltages to lower (distribution) voltages that are used for distribution to Duquesne Light's customers.

Once converted down to distribution voltages (typically 23 kV or 4 kV, except in our downtown Pittsburgh network system where there is both 11 kV and 23 kV primary distribution voltage), electricity is delivered to customers through the local distribution system. The local distribution system consists of distribution lines, transformers, switches, breakers, and other electrical equipment that Duquesne Light uses to deliver power from the various substations to the customer.

Q. Does Duquesne Light have a planning process to ensure its electric system continues to meet the needs of its customers?

A. Yes. Duquesne Light's planning process encompasses a three-year review of capital additions needed for service restoration, customer commitments, service capacity and reliability, and infrastructure support. This planning process addresses both our annual investment needs for capital additions and replacements as well as necessary investments in our energy delivery and support infrastructure to replace physical infrastructure that is either nearing obsolescence or unable to meet our customers' needs for capacity and reliability. In developing and preparing our current three-year plan (2005 – 2007), Duquesne Light determined that significant additional investment was required to ensure continued reliable service to our customers. These new requirements for capital additions formed the basis of what has been referred to as our infrastructure improvement plan. As explained below, Duquesne Light will invest approximately $530.0 million in our electrical infrastructure and supporting facilities during the three-year period 2005 through 2007. This is an increase of approximately $300.0 million when compared to the three-year period preceding 2005.

Q. Can you explain why this higher amount for additions is necessary?

A. Yes. During the past three-year period preceding 2005, Duquesne Light invested approximately $230.0 million for capital additions to restore service, satisfy customer commitments, address major equipment replacements due to failure, install new capacity to accommodate load shifts, provide short-term improvements to system reliability, and fund infrastructure support projects.

However, while these past capital additions met the immediate needs of our customers, they are not sufficient to ensure continued safe and reliable service going forward. New substation investments need to be made to increase capacity and reliability across our service territory as well as investments to rehabilitate older infrastructure and to replace and install advanced technology to improve operations and reliability.

Duquesne Light needs to proactively replace facilities and electrical equipment that, while having provided safe and reliable electric service to our customers for decades, is now nearing the end of its useful operating life and requires replacement before it fails while in service and adversely affects electric service reliability. These needs include replacing equipment in our substations that has reached the end of its useful life, upgrading areas of the distribution system through conversion of 4 kV to 23 kV voltage class, increasing substation and circuit capacity to serve the growing electricity needs of our Oakland-area hospitals and universities, and refurbishing the aging underground systems that power sections of downtown Pittsburgh and surrounding urban areas, as well as the underground residential distribution systems in our older suburban housing plans.

Q. Can you summarize the process used by Duquesne Light to determine which capital additions are necessary and when they must be added?

A. Yes. Duquesne Light identifies the need and priority for capital additions by comparing knowledge regarding the condition and use of its assets to knowledge regarding the future performance requirements of those assets. In cases when a problem with future performance is predicted, or where a need to improve performance has been identified, Duquesne Light engineers develop a variety of reasonable alternatives to resolve the problem or meet the need. Each alternative is then evaluated on its technical and financial merits and the alternative with the greatest customer value consistent with Duquesne Light service and financial objectives is recommended.

Company management reviews these recommended capital additions and challenges the underlying technical and financial facts, assumptions, and conclusions. Their challenges ensure that appropriate analytical rigor is applied to the decision-making process and ensures that each capital addition is considered within the context of all other capital needs. This is an iterative process that continues until a final decision is made on a capital addition.

Approved capital additions are included in an integrated work plan that is used by Duquesne Light planners, engineers, and project managers to ensure optimum sequencing of the many different additions made during any given year. As projects are completed, field supervisors perform project reviews to assure the scope of work has been completed and then notify the plant accounting department to ensure proper accounting treatment of the capital project.

Q. Please explain the reasons why Duquesne Light makes capital additions.

A. Duquesne Light makes capital additions in order to provide safe and reliable service to our customers. The specific capital additions for the historic and future test years are necessary for four primary reasons and are categorized accordingly in Exhibit JLC-1: (1) Service Restoration, (2) Customer Commitments, (3) Service Capacity and Reliability, and (4) Infrastructure Support.

Q. Please explain "Service Restoration" as a primary reason for making capital additions.

A. Duquesne Light customers expect their electric service to be restored promptly if it is interrupted. Service Restoration includes capital additions needed to replace equipment that has failed in service and either resulted in a service interruption to Duquesne Light customers or presented a significant risk of an imminent service interruption. This may include additions needed to replace equipment failures related to adverse weather conditions, animal contacts, and equipment that failed due to reaching the end of its service life as well as outages caused by customers and/or their equipment.

Forecasts of capital additions needed for Service Restoration are estimated based on previous years' experience.

Q. Please summarize the types of capital additions that are included in the 2006 budget for "Service Restoration".

A. In 2006, Duquesne Light's budget includes $18.0 million for Service Restoration. The 2006 service restoration program provides funding for the restoration of equipment that may require replacement due to damage caused by storms, wind, ice, or heat. Replacement includes both overhead and underground facilities. It also includes funding to replace equipment that may fail and cause customer outages or has the potential for causing imminent outages to customers.

Q. Please explain "Customer Commitments" as a primary reason for making capital additions.

A. Duquesne Light serves residential, commercial and industrial customers. All customer classes rely on us to provide service for new or remodeled homes and businesses, and also to upgrade existing services to meet new capacity requirements they may have as a result of additional load such as computers, street lighting additions and modernization. Customer Commitments also include capital additions and relocations of Company facilities that are regularly requested by governmental agencies due to highway improvements or other rights-of-way interferences. These projects include road widening, sewer and water main replacements/upgrades or other infrastructure improvements.

Forecasts of capital additions needed as a result of Customer Commitments are based upon forecasted economic conditions in the Duquesne Light service area, projected number of new customers, major customer projects that are known to us, and projects identified to us by state, county, city and local municipalities.

Q. Please summarize the types of capital additions that are included in the 2006 budget for "Customer Commitments".

A. In 2006, Duquesne Light's budget for Customer Commitments is $19.0 million. This amount funds hundreds of various sized projects to install overhead or underground distribution equipment requested by residential, commercial or industrial customers, or governmental agencies in accordance with Duquesne Light service policies.

Q. Please explain "Service Capacity and Reliability" as a primary reason for making capital additions.

A. Duquesne Light customers expect our electric system to provide sufficient electric capacity that is highly reliable. Capital additions to the Duquesne Light electric system are required to ensure that it continues to meet those needs as customer load grows or the location of load shifts within the Duquesne Light service territory. The types of additions required to ensure service capacity and reliability include circuit conversions to ensure the distribution system meets our customers voltage and load requirements, the installation of new equipment to replace deteriorated, obsolete, or failed equipment, and additions that may be necessary to improve operations.

Forecasts of capital additions needed to ensure Service Capacity and Reliability are identified by the analysis of the results of inspecting and testing equipment, analyzing system performance, and engineering studies that simulate system loadings under a variety of operating conditions.

Q. Please summarize the types of capital projects or programs that are included in the 2006 budget for "Service Capacity and Reliability".

A. The majority of Duquesne Light's infrastructure improvements are focused in the area of Service Capacity and Reliability. In 2006, Duquesne Light will invest approximately $75.4 million and $86.1 million, respectively, for Transmission and Distribution Service Capacity and Reliability. Of the approximately $86.0 million for distribution capital expenditures, approximately $36.0 million is to fund equipment replacement programs to systematically replace equipment identified to be at the end of its useful life due to operational inefficiency or obsolescence. Examples of these programs include the sectionalizer and recloser replacement program, deteriorated pole replacement program, replacement of deteriorated or damaged line equipment, minor line hardware replacement, cross arm replacement, minor voltage or reliability improvement projects and substation relay, breaker and switch replacement programs.

The remaining balance of approximately $50.0 million for distribution in 2006 is to fund ten major projects.

Q. Please describe each of the ten major capital projects included in the Distribution "Service Capacity and Reliability" budget for 2006.

A. These major capital projects exceed $3.0 million each and include additions such as new or upgraded substations and circuits, equipment to replace major distribution equipment at substations, and equipment to rehabilitate deteriorated overhead and underground distribution circuits and systems. The ten major projects are described as follows with a brief summary of need, work scope, reasoning and customer benefit, total cost, and in service date for each of the ten projects:

Service Capacity and Reliability Major Project #1: A new substation project (California Substation) needed to meet new load requirements.

The California Substation is a new substation that will consist of a single 30 MVA 138 kV to 23 kV transformer. The transformer's output will feed new 23 kV switchgear that will have a maximum of three line positions.

California Substation was installed to add capacity to eliminate an existing 12% overload at Pine Creek Substation and to eliminate projected overloads on distribution circuits Pine Creek 23712, 23714 and 23717, which primarily serve the O'Hara Township area. Converting the nearby Colfax-Pine Creek 66113 line from 69 kV to 138 kV and installing a tap to the substation will provide the transmission supply.

Duquesne Light's customers will benefit through increased reliability in this area from dividing the load among additional sources, maintaining circuit loading within design limits and increasing the operational flexibility in the area.

The substation provides service to customers in the Borough of Fox Chapel, Indiana Township and O'Hara Township areas, including commercial and light industrial customers in the O'Hara RIDC Park.

The California Substation project is estimated to cost $4.2 million with a scheduled in service date of December 2006.

Service Capacity and Reliability Major Project #2: A capacity expansion project at an existing substation (Oakland Substation) needed to meet new load requirements, relieve feeder overloads and improve system reliability.

The Oakland Substation project will replace the existing three 75 MVA 138 kV to 23 kV transformers with three 100 MVA 138 kV to 23 kV transformers. The new transformers' output will feed new 23 kV switchgear that will contain a maximum of six circuit positions. The installation of the new transformers will accommodate the installation of three new 23 kV breakers to which new 23 kV circuits will be connected.

The capacity expansion at Oakland Substation will eliminate a projected overload condition on distribution circuit Oakland-Wightman 22608 and is designed to meet continuing load growth in the Oakland area. This load growth is from institutions such as University of Pittsburgh Medical Center, Magee and Children's hospitals, as well as numerous retail businesses. In particular Duquesne Light is required to meet the load growth projected for other expansion projects currently underway by our customers. Examples include campus expansion at Carnegie Mellon University and at the University of Pittsburgh where construction has begun to add eleven new buildings at the Oakland campus.

In addition to the growing customer loads, based upon inspections and analysis, two of the three existing 75 MVA transformers at Oakland Substation are deemed to be close to the end of their service life.

The new transformers will benefit Duquesne Light customers by avoiding projected overloads in the Oakland area, which overloads could result in equipment failures and power outages. The replacement of these transformers prior to them failing in service will have significant customer and system benefits by preventing possible extended customer outages and extended contingency operation of antiquated equipment. Thus, Duquesne Light customers will benefit through improved system reliability and load transfer capabilities in the Oakland area, which is the most densely loaded area on the Duquesne Light system except for downtown Pittsburgh.

The Oakland Substation project is estimated to cost $6.9 million with a scheduled in service date of August 2006.

Service Capacity and Reliability Major Project #3: An ongoing long-term program to convert aging 4 kV circuits to 23 kV circuits needed to ensure service capacity and reliability.

The Duquesne Light system currently has approximately 285 4 kV circuits fed from approximately 150 substations, most of which were constructed between 1920 and 1965. These circuits make up approximately 35% of our distribution system. In the 1960's Duquesne Light began to install 23 kV distribution circuits to provide the capacity to meet increasing customer demands. The higher voltages reduced the losses associated with the 4 kV distribution plant because far less current is required to deliver power to our customers and an additional transformation step is eliminated.

Line circuit conversions follow a systematic approach for the removal and conversion of lower voltage 4 kV substations and circuits to higher voltage 23 kV distribution circuits. The objective of this program, which converts approximately seven to ten 4 kV circuits per year, is to improve customer's long-term reliability by reducing the frequency and duration of outages related to failed equipment that has reached its end of useful life. In addition, automated line switchgear, generally not available on 4 kV equipment, is installed during the conversion project and allows for greater operational flexibility during maintenance switching and service restoration efforts. Circuit selection criteria include evaluations of 4 kV substation equipment, distribution system condition, circuit performance, and switching and load transfer capabilities.

Duquesne Light's customers will benefit from improved reliability due to enhanced service restoration capabilities made available by automated switching, and the avoidance of unplanned outages due to end of useful life failures of 4 kV equipment.

In 2006, line circuit conversions will be completed on circuits providing service to customers in the Bell Acres Borough, Dormont Borough, Leet Township, Leetsdale Borough, the City of Pittsburgh, Oakmont Borough, and Robinson Township areas of Duquesne Light's service territory.

The in service dates for line circuit conversion projects will occur throughout 2006, and will result in the completion of capital additions of $7.6 million during that period.

Service Capacity and Reliability Major Project #4: An ongoing long-term program to rehabilitate aging Underground Residential Distribution (URD) infrastructure needed to ensure reliability.

The URD rehabilitation program is an ongoing, long-term program to systematically replace earlier URD designs that utilized submersible transformers and primary separable splicing junctions in galvanized steel or bituminous fiber vault housings installed below grade. Many of the vaults housing submersible transformers and splicing junctions are deteriorated which allow foreign material to enter the vault and either partially or completely cover our equipment. These installations create service restoration problems when a failure occurs because the foreign material must be removed before repairs can begin. These URD systems within housing developments served by Duquesne Light were constructed in the late 1960's and early 1970's. Residential customers living in these areas are experiencing higher than normal equipment failure rates due to concentric neutral corrosion, underground cable faults and splicing junction failures. These elevated failure rates correspond to equipment manufactures' life expectancy for this type of equipment. The selection criteria used to prioritize URD rehabilitation included the number of service interruptions within a rolling twelve-month period, number of equipment failures, type of URD construction and operating condition, number of customers within the plan and date of installation.

Rehabilitation of these URD facilities will include the replacement of exposed concentric neutral primary cable with the current jacketed style and the installation of permanent cable faultfinders, where appropriate. Also, submersible transformers and separable splicing junctions will be replaced with above grade equivalents.

Duquesne Light's URD customers will benefit from improved reliability due to both a reduction of the number of outages and the duration of these outages. In addition, these customers will experience improved service restoration of future outages as a result of increased operational flexibility within the rehabilitated URD system.

Projects to be completed in 2006 include URD-served residential customers in the Coraopolis Borough, Economy Borough, Moon Township, and O'Hara Township areas.

The in service dates for URD rehabilitation projects will occur throughout 2006, and will result in the completion of capital additions of $3.1 million during that period.

<u>Service Capacity and Reliability Major Project #5:</u> A capital improvement project at the existing substation (Wilmerding Substation) to address reliability concerns and projected overloads.

The Wilmerding Substation project replaces three deteriorating 30 MVA transformers with a new 75 MVA tap changing under load (TCUL) transformer connected to the 138 kV supply, resulting in a station with two 75 MVA, 138 kV to 23 kV TCUL transformers. The existing #1 and #2 23 kV transformer banks are all single-phase units (total of six) in the 85 to 90 year-old ranges. Both banks have signs of moderate to severe overheating of the oil and paper insulation causing deterioration in the paper insulation.

The project removes all of the deteriorated and over-worn distribution equipment, including undersized 23 kV buses. Aside from condition assessments of the distribution facilities, one factor that expedited the distribution upgrades was the fact that Duquesne Light's Regional Transmission Organization (RTO), PJM, has observed overload conditions following contingency scenarios in its 2009 transmission analysis. The conversion of Wilmerding Substation from 69 kV to 138 kV supply has been identified as a baseline upgrade through PJM's Regional Transmission Expansion Plan (RTEP). PJM has determined that this project will contribute to the mitigation of the identified overload conditions. The conversion will eliminate the potential loss of load because of the single point of failure associated with the stand-alone transformer. As presently designed, if the transformer or the Dravosburg-Rankin Z91 line fails, the back up supply from Wilmerding Substation, which presently does not have voltage regulation, will cause low voltage throughout the area affecting approximately 12,000 customers. The load carrying capability of these four circuits is 60 MVA. The loss of one of these 23 kV lines would likely result in customer outages until a repair is made or the maintenance is completed.

Duquesne Light's customers will benefit from this project through increased reliability in this area due to the upgrading of deteriorating equipment and increasing the operational flexibility in the area. The substation, located in the Municipality of Monroeville, provides service to customers in the Borough of Churchill, the Borough of East McKeesport, the Municipality of Monroeville, North Versailles Township, the Borough of Pitcairn, the Borough of Trafford, the Borough of Turtle Creek, the Borough of Wall, Wilkins Township, and the Borough of Wilmerding areas.

The Wilmerding Substation project is estimated to cost $6.0 million and has a scheduled in service date of December 2006.

<u>Service Capacity and Reliability Major Project #6:</u> A capacity expansion project at the existing substation (North Substation) needed to meet new load requirements, relieve voltage fluctuations, and improve system reliability.

The North Substation project replaces two 30 MVA transformers with a 75 MVA transformer connected to the 138 kV supply, resulting in a station with three 138 kV to 23 kV transformers capable of changing taps under load. Currently, excessive voltage fluctuations cause commercial customers to experience voltage control problems. These voltage control problems will be corrected by this project. As anticipated near-term load grows in this area, the required infrastructure will be in place to accommodate the addition of substations to serve the additional load with minimal delay.

The existing #2 23 kV transformer bank consists of three single-phase units in the 65 to 80 year-old ranges. They have moderate to severe overheating of the oil and paper insulation causing deterioration in the paper insulation. The #2 transformer bank is in service as a hot spare and is to be used only in an emergency.

The new 75 MVA transformer will be capable of replacing the deteriorating #1 and #2 transformer banks and eliminates the need for a 69 kV supply to serve the load at North Substation. The 69 kV to 23 kV transformer providing service to McConway-Torley will be replaced with a 30 MVA 138 kV to 23 kV transformer. Another factor, which requires expedited distribution upgrades, is that Duquesne Light's RTO, PJM, has observed overload conditions following contingency scenarios in its 2009 transmission analysis. The conversion of North Substation from 69 kV to 138 kV supply has been identified as a baseline upgrade through PJM's RTEP. Additional distribution work at North Substation will include the replacement of twelve distribution oil circuit breakers. These have been identified as reliability risks and will be replaced through Duquesne Light's breaker replacement program.

Duquesne Light's customers will benefit through increased reliability in this area by replacing deteriorating equipment prior to failure, thus reducing the risk of possible extended outages and increasing the operational flexibility in the area. The substation, located in Ross Township, provides service to customers in Hampton Township, Indiana Township, the Town of McCandless, Pine Township, the City of Pittsburgh, Reserve Township, Ross Township, Shaler Township, and the Borough of West View areas.

The in service date for this $4.9 million capital project is December 2006.

Service Capacity and Reliability Major Project #7: An ongoing long-term program to rehabilitate aging radial underground distribution systems needed to ensure reliability, improve restoration times, and address capacity needs.

This program addresses the rehabilitation and improvement of the underground portion of the distribution system and is required to ensure safe, reliable, flexible, and economical operation of the system. This rehabilitation of Duquesne Light's radial underground distribution system replaces antiquated and deteriorated duct and manhole infrastructure that supplies residential and commercial customers in the Pittsburgh area.

The existing radial underground system features cables, ducts, and manholes that were originally installed in the early 1900's. They were installed using designs and materials that were consistent with industry standards at that time. However, for the past several decades, the industry standard design has been for use of higher capacity cables that use larger conductor sizes with more insulation needed for the higher voltages of today's distribution system. Replacement materials available on the market today conform to recent industry standards and not those of the early 1900's. The existing radial system is deteriorated as a result of age and the severe operating environment associated with an underground manhole and conduit distribution system.

Radial systems, by their design configuration, offer very limited operating flexibility during contingencies. This configuration, combined with the deteriorated condition of the radial system, plus the mismatch between the existing system materials and the replacement materials available on the market today, result in reduced reliability and increased restoration time as compared to an underground network system or an overhead system.

The radial underground distribution system rehabilitation program identifies rehabilitation priorities on the basis of individual circuit reliability performance, distribution system conditions, switching and load transfer capabilities, and root cause analysis of in service equipment failures. In addition, changes in customer usage patterns, changes in location of load concentrations, and changes to system requirements are also factors that are used to prioritize rehabilitation capital additions.

Examples of the type of projects currently under implementation are the rehabilitation of distribution feeders supplied from Schenley Substation, Oakland Substation and Highland Substation. These feeders have poor operating records with multiple feeder failures. Schenley, Oakland and Highland Substations provide service to residential and commercial customers in the Bloomfield, East Liberty, Highland, Oakland, Point Breeze, Shadyside and Squirrel Hill areas of Pittsburgh.

The Duquesne Light customers supplied from those facilities will directly benefit from the improved reliability. Other customers on similar projects will also benefit because electric service reliability will be enhanced by reducing unplanned outages, new and increased customer loads will be accommodated, and increased operational flexibility resulting from the rehabilitation will improve service restoration times.

The Schenley, Oakland and Highland Substation radial underground distribution system project is estimated to cost $8.5 million, of which two phases of the project costing $4.4 million will be in service in 2006. An additional $4.1 million of capital additions will occur in 2007 to complete the remaining three phases of the project.

<u>Service Capacity and Reliability Major Project #8:</u> A project to relieve projected overloads on the feeders that provide service to the downtown area of the City of

Pittsburgh, commonly referred to as the "Golden Triangle", by installing additional feeders in the underground network system.

Downtown Pittsburgh is approximately a half square mile in area, has a load density of approximately 480 MW per square mile, and is home to critical banking, business and educational institutions.

The "Golden Triangle" is supplied from four distinct underground network systems utilizing two primary voltages, an 11 kV system and a 23 kV system. The 11 kV underground system supplies two network areas with five 11 kV feeders in each area and is fed from Forbes Substation, located in downtown Pittsburgh. The 11 kV underground network system has reached its maximum load carrying capability, therefore, all new loads in the 11 kV network area must be and are connected to the 23 kV underground network system.

The 23 kV underground network system also supplies two network areas with six 23 kV feeders in each area and is fed from Brunot Island Substation. Brunot Island Substation is located on the North Side of Pittsburgh and the primary feeders require bridge and river crossings to reach the downtown load area. The 23 kV network feeders are also currently or projected to be at or above their operational limits. Based upon a review of the network feeder cable ratings, present loading and anticipated growth on the 23 kV network system will result in overloads of up to 32% on the existing twelve 23 kV network feeders. These overloads, if not addressed, could result in equipment failures and prolonged power outages to downtown Pittsburgh.

This project will create a fifth network area to provide additional capacity to eliminate projected overloading and meet anticipated load growth in downtown Pittsburgh. The new network area will reduce load on the overloaded 23 kV feeders by establishing a new 23 kV secondary network area supplied by four new 23 kV feeders from Brunot Island Substation. The fifth network area will transfer and balance the load between the existing two 23 kV network areas, providing improved system reliability, operations and maintenance in downtown Pittsburgh. Sufficient capacity and feeder positions will be established on bus sections at Brunot Island Substation so that Duquesne Light will be capable of expanding to a six feeder network as the need arises.

The Fifth Network Area project is estimated to cost $10.9 million with an in service date of November 2006.

Service Capacity and Reliability Major Project #9: An expansion project at the existing substation (Crescent Substation) needed to address area reliability concerns, provide feeder load relief, and replace and retire antiquated equipment.

The Crescent Substation project eliminates the need to completely rehabilitate Phillips Substation, which contains extensive 69 kV facilities that are being phased out as part of Duquesne Light's long-range transmission plan. Furthermore, the project will expand 23 kV capacity and allow for the construction of a new 23 kV distribution circuit designated as Phillips 23662. The project will provide a modern substation facility with the ability to provide for the area's future transmission and distribution needs while addressing projected 23 kV distribution feeder overloads.

Duquesne Light's customers will benefit through increased reliability in this area by eliminating distribution overloads with the installation of the third Phillips distribution circuit. The replacement of deteriorating equipment prior to failure will reduce the risk of customer outages and reduce restoration times when outages do occur by increasing the operational flexibility in the area. The substation provides service to customers in the Crescent Township, Findlay Township, Hopewell Township, Independence Township, and Moon Township areas.

The total estimated project cost for Crescent Substation is $10.3 million, of which $6.3 million of capital expenditures are scheduled in 2006. An additional $4.0 million of capital additions will occur in 2007 to complete the project.

Service Capacity and Reliability Major Project #10: A capital improvement project at the existing substation (Valley Substation) to address area reliability concerns and replace and retire antiquated equipment.

Valley Substation is split between the 138 kV and 69 kV transmission systems. One 23 kV transformer, the #1 bank, is a 138 kV to 23 kV transformer supplied from the 138 kV system supported from three incoming 138 kV lines. The other two transformers, the #2 and #3 banks, are 69 kV to 23 kV transformers supplied from a single 138 kV to 69 kV autotransformer marginally supported by the Valley-Hopewell 69 kV line. In addition, much of the 69 kV station is very old and antiquated. It contains equipment including seven breakers and ten switches that have been identified as obsolete, meaning many have no replacement parts available. These substation deficiencies pose a threat to maintaining service at Valley Substation.

The load at Valley Substation is currently supplied through one 138 kV to 23 kV transformer and a single 138 kV to 69 kV autotransformer supplying two 69 kV to 23 kV transformers, only one of which has the ability to change taps under load. As a result of this configuration, the 138 kV to 23 kV transformer cannot support the load when the single contingency loss of the autotransformer removes the two 69 kV to 23 kV banks from service. The Valley Substation project will eliminate the 69 kV, thereby replacing the two 69 kV to 23 kV banks with two new 138 kV to 23 kV TCUL transformers.

Duquesne Light's customers will benefit from the proactive approach of eliminating this equipment prior to failure. The customers supplied from Valley Substation will no longer be impacted by the loss of one 138 kV to 69 kV transformer or the failure of associated substation equipment. Furthermore, the project will provide a dependable supply source to customers with an improved voltage profile. That is, a single contingency will not degrade the voltage or cause loss of load.

The substation provides service to customers in the town of Beaver, the Borough of Beaver Falls, Daugherty Township, the Borough of East Rochester, the Borough of Eastvale, the Borough of Freedom, the Borough of New Brighton, New Sewickley Township, Patterson Township, Pulaski Township, the Borough of Rochester, Rochester Township, and White Township areas.

The total estimated project cost for Valley Substation is $5.7 million of which $4.7 million of capital expenditures are scheduled for 2006. An additional $1.0 million of capital additions will occur in 2007 to complete the project.

Q. **Please explain "Infrastructure Support" as a primary reason for making capital additions.**

A. To meet the critical needs of Duquesne Light customers requires more than an electric distribution system. It requires assets needed to support the workforce who operate and maintain that system and provide other services to our customers. Infrastructure Support capital additions include items such as new vehicle purchases needed to replenish our fleet, information processing system improvements needed to provide customer account, billing, and payment processing services, upgrades to existing facilities, and the construction of new facilities needed to support our workforce.

Forecasts of capital additions for Infrastructure Support are based on past experience for items such as facility upgrades, and on analysis of needs for items such as new facilities, vehicle replacements, and information system improvements.

Q. Please summarize the types of capital projects or programs that are included in the 2006 budget for "Infrastructure Support".

A. In 2006, Duquesne Light will invest $21.5 million in Infrastructure Support projects. Of that amount, approximately $5.0 million and $4.5 million, respectively, are for annual vehicle and information technology-related programs. Approximately $2.6 million is for annual facility improvement projects.

The remaining balance of approximately $9.4 million in 2006 is to fund two major projects.

Q. Please describe each of the two major capital projects included in the "Infrastructure Support" budget for 2006.

A. These two major capital projects include facilities additions as follows:

Infrastructure Support Major Project #1: A Duquesne Light service center is under construction at Preble Avenue in Pittsburgh to ensure our customers continue to be served by a workforce properly supported with shops, storage areas, and other workspace facilities needed to ensure safety, environmental compliance, and efficiency.

The new Preble Service Center, located on Pittsburgh's North Side, will replace nearby buildings that date back almost 100 years. The existing buildings are home to construction crews that service the underground network system that provides electric service to downtown Pittsburgh, as well as construction crews that service the overhead lines that provide electric service to the surrounding neighborhoods of Pittsburgh. These buildings, while being centrally located to serve the downtown Pittsburgh area, are undersized, designed inefficiently, challenging to maintain and meet current safety and environmental compliance, require significant structural and building system renovations to meet current building codes, and are not designed to accommodate a modern day service facility.

The new service center, being built on existing company-owned property will remain centrally located in order to effectively serve the downtown and surrounding Pittsburgh area, is designed to meet current and future service center requirements. The new building will enable crews to continue to provide a high level of service and reliability to the Pittsburgh area. Crew response times will improve as a result of reduced traffic congestion and the ability to load and unload materials faster due to a more efficient building and yard design. Safety and environmental compliance will be enhanced and more efficient to maintain. The new building will contain a negative pressure HVAC system for the lead shop as well as a waste handling building for roll-off material extracted from manholes and vaults and a water oil separator to prevent oil from entering the sewers or the river. These major environmental improvements will have direct benefit to Duquesne Light's employees and the general public.

The in service date for the Preble Service Center is September 2006 and is an $11.2 million capital project.

<u>Infrastructure Support Major Project #2:</u> A Duquesne Light training center is under construction at Woods Run in Pittsburgh to ensure our customers continue to be served by a workforce properly skilled to operate and maintain Duquesne Light's complex transmission, distribution and other technical systems as well as our information and business support systems.

The new Woods Run Training Center, built on existing company-owned property within the City of Pittsburgh, will replace a 44 year-old makeshift overhead line-training site located fifteen miles north of Pittsburgh that is undersized, requires significant structural and building system renovations and is not designed to accommodate a modern day training center.

The new training center is needed to meet current and future training needs of Duquesne Light. The Company will see considerable attrition in the next five to ten years due to retirement and, in order to continue to employ a highly skilled workforce, will require a new facility to train a significant number of new workers. The new Woods Run Training Center will consolidate all of the training for Duquesne Light's operations employees to one site. This will allow a more consistent, effectively administered program in an environment that promotes better understanding and learning. It will also be home to the Company's Electrical Distribution Technology (EDT) partnership program with the Community College of Allegheny County. The Woods Run Training Center will also include substation, telecommunication and underground training, as well as commercial drivers' license training, safety compliance training, first aid, bucket rescue and CPR training.

The availability of public bus service to the new training center, which did not exist at the former overhead line-training site, will provide ease of access not only for company employees, but also for external trainees involved in the EDT program. The new training center will greatly increase training efficiency as the new facility will have the capability to perform overhead line-training indoors during inclement weather, an option not available to trainees today.

The in service date for the Woods Run Training Center is August 2006 and is a $7.5 million capital project.

Q. Are the capital additions described in your testimony and presented in Exhibit JLC-1 necessary?

A. Yes, they are. The additions described previously and included in Exhibit JLC-1 constitute necessary capital additions required to meet the needs of Duquesne Light customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit JLC-1

Duquesne Light Company

2005 – 2007 Capital Budget

($ Thousands)

	2005	2006	2007	Total
Service Restoration	$19,000	$18,000	$18,000	$55,000
Customer Commitments	23,000	19,000	19,000	61,000
Service Capacity & Reliability – Transmission	27,950	75,385	43,000	146,335
Service Capacity & Reliability – Distribution	54,550	86,115	66,000	206,665
Infrastructure Support				
Facilities	12,500	12,000	7,000	31,500
Vehicles	7,000	5,000	5,000	17,000
Information Technology	6,000	4,500	2,000	12,500
Total	**$150,000**	**$220,000**	**$160,000**	**$530,000**

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Statement No. 4

Direct Testimony of Stephen A. Wreschnig

DIRECT TESTIMONY OF STEPHEN A. WRESCHNIG

Q. Please state your full name and business address.

A. Stephen A. Wreschnig, 411 Seventh Avenue, Pittsburgh, Pennsylvania 15219.

Q. What is your position at Duquesne Light Company ("Duquesne Light" or "Company")?

A. I am employed by Duquesne Light in the Finance Department as Manager, Forecasting and Economic Analysis.

Q. What are your current responsibilities?

A. I direct the forecasting of customer energy sales, revenues, and peak demands. In addition, I oversee the analysis of load research data and the development of historical and forecasted customer- and rate class-specific hourly demands.

Q. What is your educational background?

A. I graduated from Michigan State University in 1978 with a Bachelor of Arts degree in Economics and from the University of Wisconsin in 1980 with a Master of Science in Economics.

Q. Please describe your professional experience.

A. I was employed by Wisconsin Electric Power Company from1980 until 1990. While there, my responsibilities included the forecasting of local economic activity and energy sales. I joined the Rates and Regulatory Affairs Department of Duquesne Light in 1990 and, until 1997, was responsible for energy, peak, and revenue forecasting. In 1997, I joined PNR & Associates as Director where I was responsible for applying customer research to clients in the electric utility industry. In 1999, I rejoined Duquesne Light as Director in the Finance Department.

Q. What is the purpose of your testimony?

The purpose of my testimony is to explain the development of the Company's kWh sales forecast, budget revenue forecast, and the derivation of the demand allocators employed in the cost of service studies.

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes, I am sponsoring Exhibit SAW-1 which summarizes the Duquesne Light kWh sales forecast. Exhibit SAW-1 contains actual calendar-year kWh sales data for the 2002-2005 period and forecast sales data for 2006. The table shows the actual sales as well as the annual change in both kWh and percentage terms.

Q. How was the kWh sales forecast for 2006, summarized in Exhibit SAW-1, developed?

A The Company employs a series of econometric models in the development of its short- and long-term energy forecasts for the residential, commercial, and industrial customer classes.

Q. Please describe the model used to develop the kWh sales forecast for the Residential customer class.

A The modeling of residential energy consumption can be disaggregated into three distinct analyses. The first is estimating the number of customers. The second is determining what appliances these customers will have. The third is estimating the intensity at which these appliances are used. The Duquesne Light Residential Energy Model follows this general approach. A forecast of customers is developed based on historic trends. The appliance stock decision is simplified, because of data availability, to assumptions concerning the saturations of electric space heating and electric heat pumps in the service area. This data is available since customers with these appliances are segregated by rate class. The appliance use decision is modeled by econometrically estimating a demand model of the average use per customer for each of the three major residential rate classes, RA, RS, and RH. In each of the models, kWh per customer is assumed, consistent with standard economic theory, to be a function of the price of electricity and personal income. In addition, since a high percentage of residential electricity consumption is weather sensitive because of electric heating, air conditioning, and furnace blowers, measures of the weather are included in the specification. Heating degree days (HDD) are the winter measure and the temperature/humidity index (THI) is the summer measure. Linear regression was used to estimate these models utilizing data from the Duquesne Light billing records, historic economic data from Global Insight, a well-respected economic consulting firm, and weather data obtained from the National Oceanic & Atmospheric Administration (NOAA) and Air Science Consultants, Inc.

Q. **Does the modeling of kWh sales to the Commercial and Industrial customer classes follow the same approach as the Residential Model?**

A *Not really. Since electricity in the commercial and the industrial sectors of the* economy is a factor of production, the modeling of kWh sales to these sectors is disaggregated into two separate analyses: the projection of future levels of economic activity and how this predicted level of economic activity, along with prices and weather, will affect future electricity consumption. To this end, the Duquesne Light Commercial and Industrial Energy Model models electricity sales to these customer classes separately for groups of customers based on Standard Industrial Classification (SIC) code.

Total electricity sales to those customers in the commercial sector of the economy, as classified by SIC code (Wholesale and Retail Trade, Services, etc.), are modeled based on the assumption that economic activity in the commercial sector is influenced solely by local factors that influence the demand for the services provided by this sector. These are assumed to be demographic factors such as the number of households or population and economic factors such as local personal income. As a result, the demand function for kWh sales for each of the SIC-specific commercial groups was specified with kWh sales as a function of electricity price, weather, and local economic/demographic factors. Linear regression was used to estimate these models utilizing data from Duquesne Light billing records, historic economic data from Global Insight, and the weather data obtained NOAA and Air Science Consultants, Inc.

Total electricity sales to those customers in the industrial sector of the economy, as classified by SIC code (Primary Metals, Non electrical Machinery, etc.), are modeled based on the assumption that this sector of the local economy is an "export-based" sector, one that sells or competes in the national or international market. As a result, economic activity in this sector is influenced by the demand for the national output of the particular industry. The price of electricity also has the potential to influence electricity sales to this sector. In addition, weather can also be considered to have a potential impact on sales to this sector since some load for these industrial customers is for administrative facilities that will have heating and/or air conditioning load. As a result, the demand function for kWh sales for each of the SIC-specific industrial groups was specified with kWh sales as a function of electricity price, weather, and the national demand for the output of the specific industry as measured by Industrial Production Indices calculated by the Federal Reserve Board. Linear regression was used to estimate these models utilizing data from Duquesne Light billing records, historic economic data from Global Insight, and the weather data obtained from NOAA and Air Science Consultants, Inc.

Q. How were these models used to forecast kWh sales?

A Billing-month forecasts were developed by extrapolating the results of the model estimations into the future utilizing projections of residential customer growth, local economic and demographic projections and assuming "normal" weather and no changes in the current price of electricity.

The number of residential customers in each rate class is assumed to change consistent with the trend experienced since 2003. The number of customers is expected to increase at annual rates of 1.8 percent and 1.1 percent for rates RH and RA, respectively. The number of customers in rate RS is expected to decline at a 0.2 percent annual rate.

The local economic forecast utilized was the forecast for the Pittsburgh Metropolitan Statistical Area (MSA) developed by Global Insight. In general, the local economy is expected to improve in 2006. Local employment is projected to increase by 1.2 percent in 2006, attaining the 2001 employment level, after increasing by only 0.3 percent in 2005. The national forecast was also developed by Global Insight. Nationally, the economy, as measured by Gross Domestic Product is expected to continue to experience steady growth, growing by 3.1 percent in 2006 after growing by 3.5 percent in 2005.

"Normal" weather, for forecasting purposes, was assumed to be the average weather that has occurred since 1960 as reported at Pittsburgh International Airport.

Forecasted unbilled kWh by rate class were estimated from the projected billing month kWh by applying the historical unbilled/billed kWh ratios by rate class. These unbilled kWh were used to calculate the projected calendar-month kWh that are incorporated into the budget.

Q. How was the forecast of kWh sales to the Street Lighting customer class developed?

A For the Street Lighting rate classes that have metered consumption (AL, SE, and MTS) kWh sales and billed kW were assumed to remain at the level that occurred during the most recent 12 months. At the time the forecast was prepared this was the September 2004-August 2005 period. For those Street Lighting rate classes whose bills are based on lamp count (SH, SM, and PAL), lamp counts were assumed to remain at the August 2005 level and kWh sales were calculated based on the nominal energy usage per lamp as specified in the Duquesne Light Schedule of Rates.

Q. Please briefly describe the forecast shown in Exhibit SAW-1.

A. With only a 0.2 percent projected increase in the number of residential customers overall, the forecast of kWh sales to the Residential class for 2006 is dominated by the fact that normal weather is expected 2006. This is in stark contrast to 2005 which had the third warmest summer in Pennsylvania in the 111 years of national record keeping. As a result, kWh sales to this class are expected to decline by 3.6 percent. Commercial sales, less impacted by the weather while boosted by the expected improvement in the local economy, are expected to increase by 1.9 percent in 2006. Industrial sales, highly dependent on the national demand for manufactured goods, are expected to increase by 3.2 percent as kWh sales to the durable good sector are expected to increase.

Q. How were the budgeted retail revenues incorporated in Filing Schedule B-3 of DLC Exhibit 2 derived?

A. The billing-month kWh sales forecast, described above, was disaggregated by rate into kWh consumption blocks based on the historical 2005 kWh distribution by block. Billed kW was assumed in the forecast to maintain the same proportion to kWh that occurred in 2005. The billing month retail revenues associated with the billing-month sales forecast were derived by applying the existing tariff rates to the corresponding forecasted billing determinants. The monthly unbilled revenues were then estimated based on each month's projected unbilled kWh priced at the projected average billed revenues per kWh. These unbilled revenues were then used to convert billing-month revenue to calendar-month revenue for budget purposes.

Q. Please explain the source of the customer load data used to develop the customer class demand allocators employed in the company's cost of service study.

A. Duquesne Light collects 15 minute interval load data from meters on a sample of customers on Rate Schedules RS, RA, RH, GS/GM, and GMH. This interval data is collected from all customers on Rate Schedules GL, GLH, L, and HVPS. For customers on the rate schedules that are represented by samples, the sample data was extrapolated to determine the hourly demands for the entire rate class.

Q. How were the values for the coincident peak (1CP) demand allocator derived?

A. The development of the 2005 weather-normalized coincident peak demand allocators (1CP) was a two-step process. First, a linear regression analysis of 2005 summer peak hours was utilized to determine both the time and the value of the system peak that would have occurred in 2005 under "normal" peak producing weather conditions. The weather variable was the temperature-humidity index. The value of the system peak was 3,003MW (excluding 4MW of non-retail loads), measured at the generation level.

Next, regression models were developed to determine the weather-sensitivity of the actual (for metered loads) and inferred (for sampled loads) rate class-specific hourly loads during the summer. The results of this analysis and the rate class-specific loss factors, described in DFR IV-E-1, allowed for the calculation of the rate class-specific weather-normalized generation-level loads at the time of the weather-normalized system peak. The sum of these normalized rate class-specific peak loads at the time of this peak was 0.9 percent more than the weather-normalized system peak of 3,007 MW. The difference, due to normal sampling error, was spread over the sampled loads.

Q. How were the non-coincident peak (NCP) demand allocators derived?

A. The Company determined the rate class values for the non-coincident peak (NCP) demand allocator at the generation-level. This allocator is the starting points for development of the other NCP allocators, such as NCP-Primary and NCP-Secondary, used by Mr. Gorman in the Class Cost of Service Study. The derivation of these other NCP allocators is described in Mr. Gorman's testimony. The generation-level NCP demand allocator for each of the fully metered large customer rate classes was calculated by summing the meter readings for the 12 months ended August 2005 by rate and hour, finding the maximum hourly MW, and adding line losses based on rate class-specific loss factors. For those rates classes where there were meters on a sample of customers (RA, RH, RS, GS/GM, and GMH), the generation-level NCP was defined as the hour that the rate class maximum MW was attained, adjusted for line losses, during the month of August 2005 for RA, RS, and GS/GM and during the month of December 2005 for RH and GMH.

Q Does this conclude your direct testimony?

A. Yes, it does.

Duquesne Light Company
Annual Retail Sales by Customer Class
2002-2006

	2002	2003	2004	2005	2006
	---millions of kWh---				
Residential	3,924.1	3,758.7	3,885.6	4,133.6	3,984.0
Commercial	6,457.5	6,345.6	6,453.7	6,566.0	6,692.6
Industrial	3,328.4	3,189.1	3,228.6	3,128.4	3,229.4
Lighting	70.1	69.7	69.7	68.6	69.1
Total	13,780.1	13,363.1	13,637.5	13,896.5	13,975.2
	---Year-To-Year Change (millions of kWh)---				
Residential		(165.4)	126.9	248.0	(149.6)
Commercial		(111.9)	108.0	112.3	126.7
Industrial		(139.3)	39.5	(100.2)	101.0
Lighting		(0.5)	0.0	(1.1)	0.5
Total		(417.0)	274.4	259.0	78.6
	---Year-To-Year Change (percent)---				
Residential		-4.2%	3.4%	6.4%	-3.6%
Commercial		-1.7%	1.7%	1.7%	1.9%
Industrial		-4.2%	1.2%	-3.1%	3.2%
Lighting		-0.6%	0.0%	-1.5%	0.7%
Total		-3.0%	2.1%	1.9%	0.6%

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

Statement No. 5

Direct Testimony of Mauro L. Macioce

DIRECT TESTIMONY OF MAURO L. MACIOCE

Q. Please state your full name and business address.

A. Mauro L. Macioce, 411 Seventh Avenue, Pittsburgh, PA 15219

Q. What is your position at Duquesne Light Company ("Duquesne" or "Company")?

A. I am the Director of Taxes

Q. How long have your worked at Duquesne?

A. I have been an employee of Duquesne since February of 2003.

Q. What are your current responsibilities?

A. I am in charge of the overall tax function for Duquesne Light Holdings, Inc. ("Holdings") and it subsidiaries, which include Duquesne. Holdings is the parent company of Duquesne.

Q. What are your qualifications, work experience and educational background?

A. I have included that information as Exhibit MLM-1 to my testimony.

Q. What is the purpose of your direct testimony regarding Duquesne's request for increased rates?

A. My purpose is to describe and explain Duquesne's tax expense and related tax information.

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes, I am. I am co-sponsoring Duquesne's Income Statement as it relates to taxes and the Balance Sheet as it relates to deferred and prepaid taxes. The specific schedule references are DLC Exhibit 2 (Future) and 3 (Historic) B-1, B-2, B-5, C-6, D-16 and D-18. I am sponsoring all the Data Filing Requirements and

Schedules concerning Taxes. Specifically, the exhibits I am sponsoring in this proceeding are:

Item #	Subject Matter
DFR II-D-14	Debt Interest for Income Tax Calculation
DFR II-D-15	Schedule of Taxes Other than Income
DFR II-D-16	Schedule of Current and Deferred Tax Expense
DFR II-D-17	Schedule of Income Tax Refunds
DFR II-D-18	Prepaid and Deferred Income Tax Charges
DFR II-D-19	Federal Corporate Graduated Income Tax Rates
DFR II-D-20	Cost of Removal
DFR II-D-21	Income Tax Gain/Loss Carryovers
DFR II-D-22	Elim of Tax Savings by Payment of Interest on CWIP
DFR II-D-23	Consol. Tax Return Election - §1552
DFR II-D-24	Deferred Taxes Related to Depreciation
DFR II-D-25	Deferred Investment Tax Credits

Q. Please explain how these exhibits were prepared?

A. All were prepared either by me or under my direction or supervision. They were prepared in accordance with Commission requirements and Internal Revenue Service procedure and guidance.

Q. Could you explain Duquesne Light Company's tax expense for the historic test year?

A. For the historic tax year the Company has used its December 31, 2005 financial statement tax provision information to calculate its current and deferred income tax expense.

Q. Could you explain Duquesne Light Company's tax expense for the future test year?

A. In DLC Exhibit 2 (Future) D-18 the Company used the 2006 budgeted income and expenses to calculate the current federal and state income tax expense. This exhibit also shows a calculation of federal deferred income tax expense.

Q. Would you explain the treatment of cost of removal in the income tax calculation?

A. In determining the pro forma operating expenses for the cost of service, the customer is charged with removal costs of retired plant through the net negative salvage adjustment. That adjustment is also used in the calculation of pro forma income taxes for the cost of service. The overall effect is, to the extent the customer is required to bear the cost of removal through the net negative salvage adjustment, he/she is also entitled to receive the benefit of any reduction of income taxes which results from including this adjustment in the pro forma income tax calculation.

Q. How does Duquesne file its federal tax returns?

A. Duquesne is part of a consolidated federal income tax filing with its parent Holdings.

Q. Are you aware of the Pennsylvania Public Utility Commission's ("Commission") procedure to reflect a share of the losses by entities included in a consolidated income tax return?

A. Yes, I am.

Q. Have some of the companies that join in a consolidated return with Duquesne experienced such losses?

A. Yes.

Q. Have you made a calculation of the consolidated tax savings adjustment for this proceeding?

A. Yes, I have.

Q. Please describe your calculation?

A. I used the tax losses for 2004 and the estimated losses for 2005 and for each year allocated losses to Duquesne based on the ratio of the taxable income of Duquesne to all of the companies in the consolidated group that had taxable income in each year. I have calculated the reduction of Duquesne's current federal taxes to provide a share of tax reductions created by these companies' losses on the consolidated tax return in accordance with the procedure employed by the Commission. My calculations use data from 2004 and 2005, as it is most representative of the future operations of the company. This data was also adjusted to reflect the current corporate structure of Holdings. Based on my calculations the total consolidated tax savings adjustment to be allocated to the Company for the test year is approximately $942 thousand. The calculation of this adjustment is attached as Exhibit MLM – 2.

Q. Has the amount calculated above been used in the pro forma income tax calculations?

A. No it has not. This is the amount allocated to Duquesne as a whole. It must be reduced to assign a portion of the loss to the FERC regulated transmission business. This is done at Exhibit No._(LAC-2). The amount used in the pro forma income tax calculation is $754 thousand. This is the amount that has been allocated to the Company's distribution assets for purposes of this distribution rate filing.

Q. Does the Company utilize accelerated tax depreciation?

A. Yes, the company uses accelerated depreciation. From 1971 to 1980 the Company elected to calculate tax depreciation under the provisions of the Class Life System (ADR) as provided by the Revenue Act of 1971. From 1981 to 1986 the

Company elected to calculate tax depreciation under the Accelerated Cost Recovery System (ACRS) as provided by the Economic Recovery Tax Act of 1981. From 1987 to the present the Company has elected to calculate tax depreciation under the provisions of the Modified Accelerated Cost Recovery System (MACRS) as originally provided by the Tax Reform Act of 1986 and as modified is subsequent Acts.

Q. Please comment on the Deferred Income Taxes presented in your tax expense.

A. In this rate case, Duquesne is reflecting deferred income taxes resulting from the excess tax deduction from the use of accelerated depreciation methods over the book depreciation for eligible property. Duquesne's entitlement to the use of accelerated depreciation provisions on post-1970 properties for federal income tax purposes is dependent upon the use of a normalization method of accounting for the resulting income tax reductions in determining cost of service for rate making. The measure of income taxes to be normalized is the income tax effects of the difference between accelerated depreciation using tax lives and straight-line depreciation using book life spans. Absent normalization accounting for ratemaking purposes, Duquesne would be required to use a straight-line method with book lives in determining its tax depreciation allowance for federal income tax purposes.

In accordance with Commission policy, deferred income taxes related to pre-1971 properties and state income taxes are not included in the income tax provisions for this filing.

Q. Could you explain how you have accounted for deferred taxes in this filing?

A. Federal accumulated deferred income taxes ("ADIT") related to plant in service, recorded in account 282 have been deducted from rate base. These amounts have been reduced by the ADIT related to the prepayments on income taxes related to contributions-in-aid of construction. In addition, consistent with my understanding of Commission practices there are no ADIT for state income taxes on property. This represents the flow-through treatment for those accelerated depreciation amounts adopted by the Commission.

Q Are there any investment tax credits the Company has reflected in the income tax calculations for this rate filing?

A. The Company has reflected $1.455 mil of investment tax credits (ITC) in its tax calculation for this filing. This amount represents the amount of deferred ITC amortization for the year. Under the provisions of the Revenue Act of 1971, Duquesne elected to treat the ITC in rate proceedings by reducing taxes over the life of the property and not deducting the accumulated amount of the credit from rate base. As a result, the ITC amounts are restored through reductions to the income tax provision, ratably, over a period of years, which is equivalent to the useful life of the property that produced it. These reductions are shown on DLC Exhibit 2 (Future), Schedule D-18.

Q. How does the Company handle local and gross receipts taxes?

A. The Utility Gross Receipts Tax ("UGRT") return is filed on an annual basis. The UGRT is a percentage of the taxable gross receipts of the Company. Upon filing of the annual return an estimated payment is made that will cover approximately 90% of the future year's tax. Other local taxes are filed on an annual basis. Estimated amounts of the tax due are paid on a quarterly basis.

Q Does this conclude your direct testimony?

A. Yes, it does.

Exhibit MLM-1

Qualifications and experience of Mauro L. Macioce.

Name: Mauro L. Macioce

Title: Director of Taxes

Duquesne Light Company Responsibilities:

February 2003-Present
Administration of corporate wide tax function. Responsibilities include Federal and state tax planning and research regarding acquisitions, dispositions, business combinations and continuing operations. Oversee tax compliance function for income, franchise, sales and use, property and utility-based taxes. Manage Federal and state tax examinations. Presentation of all financial statement tax related information. Compliance with Section 404 of the Sarbanes-Oxley Act.

Past Job Experience:

May 1996-January 2003
Interstate Hotels Corporation
Director of Taxation – Managed worldwide tax function for multi national publicly traded hotel company with revenues of $650 million.

December 1993-April 1996

PricewaterhouseCoopers, LLP -Tax Manager

December 1989-November 1993
Deloitte & Touche, LLP – Senior Tax Consultant

January 1986-November 1989
PricewaterhouseCoopers, LLP – Audit Senior Accountant

Education:

Robert Morris University, M.S. Taxation, 1995
Pennsylvania State University, B.S. Accounting, 1984
Certified Public Accountant

Exhibit MLM-2

Consolidated Tax Savings Adjustment

(000's)

Company	Taxable Income	Taxable Income Companies	Tax Losses
2004:			
Duquesne Light Holdings, Inc.	(7,711)	-	(7,711)
Cherrington Insurance, LTD	(137)	-	(137)
Duquesne Energy Solutions	2,918	2,918	-
DQE Enterprises, Inc.	(39)	-	(39)
DQE Systems, Inc.	2,379	2,379	-
DQE Capital Corporation	(913)	-	(913)
DQE Financial Corporation	46,892	46,892	-
Duquesne Light Company	58,818	58,818	-
Total Taxable Income	102,207	111,007	(8,800)
Allocation Percentage		53%	
Loss Allocated			(4,663)
Tax Effected Loss Allocation			(1,632)
2005:			
Duquesne Light Holdings, Inc.	(1,414)	-	(1,414)
Cherrington Insurance, LTD	(35)	-	(35)
Duquesne Energy Solutions	27,318	27,318	-
DQE Enterprises, Inc.	(300)	-	(300)
DQE Systems, Inc.	2,823	2,823	-
DQE Capital Corporation	383	383	-
DQE Financial Corporation	26,637	26,637	-
Duquesne Light Company	39,722	39,722	-
Total Taxable Income	95,134	96,883	(1,749)
Allocation Percentage		41%	
Loss Allocated			(717)
Tax Effected Loss Allocation			(251)
Consolidated Tax Savings		**(942)**	

Statement No. 6

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SECRETARY'S BUREAU

DUQUESNE LIGHT COMPANY

Direct Testimony

of

Paul R. Moul
Managing Consultant
P. Moul & Associates

Concerning
Rate of Return

Duquesne Light Company
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
AMT	Alternative Minimum Tax
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DLH	Duquense Light Holdings, Inc.
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
g	Growth rate
GAAP	Generally accepted accounting principles
GDP	Gross Domestic Product
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
M&A	Merger and Acquisition
MM	Modigliani & Miller
MLP	Master Limited Partnerships
MPL	Minimum Pension Liability
OCI	Other Comprehensive Income
POLR	Provider of last resort
PPUC	Pennsylvania Public Utility Commission
PUC	Public Utility Commission
PUHC	Public Utility Holding Company

GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

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 Duquesne Light Company ("Duquesne Light" or the "Company"), an opportunity to earn on its jurisdictional rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into fourteen (14) 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 cost of common equity and rate of return 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% rate of return on common equity. The Company's proposed rate of return on common equity 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, including its high quality of customer service and as relatively efficient provider of energy services. With this return, I have presented on Schedule 1 the weighted average cost of capital, which is 9.09%. 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. Duquesne Light is wholly-owned subsidiary of Duquesne Light Holdings, Inc ("DLH" or the "Parent Company"). The Company provides electric delivery service and provider of last resort ("POLR") service to approximately 587,000 customers in Allegheny and Beaver counties. In 2005, electric sales in Mwh for Duquesne Light were comprised of approximately 30% to residential, 48% to commercial, and 22% to industrial customers. Approximately 11% of the Company's sales were to heating customers. This means that the Company's sales in both the winter and summer periods are sensitive to variations in temperature. Further, approximately 49% of the Company's sales are related to POLR service.

The Company is presently operating under its third provider of last resort ("POLR III") rate plan. Under POLR III, residential and small commercial customers obtain service under fixed rates through December 31, 2007. For large commercial and industrial customers, the POLR III rate plan provides either a fixed price that extends through May 31, 2006 or real-time spot prices based upon the PJM Interconnection market. Due to the restructuring of the industry, the Company is now faced with higher costs to acquire electricity for its customers. The implication is that there is more uncertainty because when sales vary from forecast loads, the acquisition of additional electricity will typically occur at higher spot prices.

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 an electric utility, such as Duquesne Light. 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 indicates that the Company's rate of return on 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 preferred 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 electric companies. The criteria that I used to assemble the nine company proxy group will be described later in my testimony. The companies in the electric proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

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

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not separately measured the cost of equity for the individual companies within the Electric 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 Company's 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, reliance on a single method can provide an incomplete measure of the cost of equity. 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.

	Electric Group
DCF	10.40%
RP	11.81%
CAPM	11.54%
Comparable Earnings	16.10%
Average	12.46%
Median	11.68%
Mid-point	13.25%

From these measures of the cost of equity, the average and the median values are 12.46% and 11.68%, 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 11.25%. 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 this case is at the top of the range.

The exemplary performance of the Company's management is described in the testimony of Mr. Morgan O'Brien. Mr. O'Brien explains the many initiatives that the Company has undertaken, which have produced high quality service at reasonable prices. In particular, Mr. O'Brien has shown that the Company ranks high in customer service and its reliability has been exceptional. In recognition of its outstanding performance and its goal of maintaining reasonably priced electric delivery service, the Company should be granted an opportunity to earn an 11.75% rate of return on common equity.

I should 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 electric companies. Indeed, the average Value Line Timeliness Rank for my Electric 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 the companies that are contained in the Electric Utility (East) group are ranked 83 out of 98 industries for probable performance over the next twelve months according to Value Line. 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. I also believe my recommended cost of equity of 11.75% is appropriate in this case 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 and the large construction projects underway.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Today, electric utilities are faced generally with meaningful changes in the fundamentals that affect their operations, while cost of service pricing continues to dominate much of their business profile. On the national level, the passage of the National Energy Policy Act ("EPACT") and the issuance of FERC Order Nos. 888 and 889 and Order No. 2000 initiated sweeping changes that fundamentally altered the structure of the electric utility business. EPACT removed certain impediments to the construction of non-utility generators ("NUGs") by utility affiliates and by independent developers. Order Nos. 888 and 889 have provided these generators, as well as other utilities, with the ability to sell their energy directly to wholesale customers, as well as to end-use customers in states with retail competition. Order No. 2000 encouraged the formation of Regional Transmission Organizations ("RTO") that offer non-discriminatory transmission service. Duquesne Light is part of the PJM Interconnection. While generation in some parts of the U.S. has become a non-regulated competitive business, the transmission and distribution of electricity will likely continue under some form of rate regulation. The recent passage of the EPACT further highlights the emphasis being placed upon the reliability and structure of the electric utility industry.

Q. Have these changes brought about increases in the risks facing electric utilities generally?

A. Yes. Aside from its traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks are now evolving in a new era for the electric delivery business in Pennsylvania. The risk of distributed generation will continue to be a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in microturbines and potential commercialization of fuel cells, utilities face the potential for declines in revenue from transmission and distribution of electricity. In addition, a utility retains the obligation to provide reliable delivery service and must continue to invest in its rate base to fulfill that obligation. There are other challenges related to siting and permitting, giving rise to additional costs and delays that could impact reliability.

The obligation to serve also represents a key risk factor for the local delivery of electricity. The risks facing the electric utilities are clearly different from, those that existed in the past. Investors generally are risk-averse, and with increased uncertainty will require compensation for higher risk.

Q. What are the primary risk factors facing the electric utility industry?

A. In the new environment, competitive issues have or will develop due to the convergence of energy sources and bypass arising from self-generation or distributed-generation. Regulatory risks include the overall framework of ratesetting, cost allocation and rate design issues, and the level of return that will be allowed.

The financial structure of the electric business is uncertain due to the structure and term of relationship with end-users, the adequacy of capital recovery, counter-party risk, potential for financial penalties associated with operational problems, and growth in the utilization of the transmission and distribution network by non-affiliated generators and marketers. The August 14, 2003 blackout that affected 50 million people represents a case-in-point regarding some of these issues.

Q. Please discuss further the evolving risks for electric utilities.

A. With increased emphasis on market-determined prices and open access of the transmission network, a new dimension has been opened in the electric utility business. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition. Hence, deregulation of certain segments of the electric utility business provides significant downside risk due to loss of revenues, but provides little upside potential due to the limitations placed on returns by regulators.

Q. What changes have occurred in Pennsylvania as a result of a move to more competitive markets for electricity?

A. On January 2, 2000, customer choice was fully available in Pennsylvania for electricity. From that point forward, Duquesne Light's responsibility became primarily the provision of delivery service at regulated prices, while it also retained the responsibility for POLR service to customers that do not elect competitive energy suppliers. The restructuring of the electric business in Pennsylvania has been underway for several years. The rates being considered in this case relate solely to the unbundled delivery service.

Q. Are there other specific risk issues facing the Company?

A. Yes. The Company's risk profile is influenced by electricity sold/delivered to commercial and industrial customers, which together represents approximately 70% of Mwh sales. According to the Electric Power Annual 2004 report published by the EIA, C&I customers generally represent 63% of Mwh sales. Sales to high volume customers are usually thought to be of higher risk than sales to other classes of customers. Success in this segment of the Company's market is subject to (i) the business cycle, (ii) the price of alternative energy sources, (iii) pressures from alternative providers, and (iv) for industrial customers, variations in usage caused by operational factors. In fact, the Company's twenty largest customers, many of which are engaged in primary metals, chemicals, manufacturing, financial services, health care, and utilities, represented 3,224,430 of Kwh sales in 2005. Moreover, external factors can also influence the Company's sales to these customers which face competitive pressures on its own operations from other facilities outside the Company's service territory.

Q. Since the Company has divested its electric generation plants, has not the risk faced by Duquesne Light declined since its last rate case in 1987?

A. Certainly, the Company's risks have changed since 1987. Today, the Company is faced with a new set of risks that were not present in 1987. Without its own source of generation, the Company must rely upon other generators to provide the energy needs of its customers. As a preliminary matter, the hierarchy of claims on the Company's revenues indicate that the generator (i.e., the wholesaler) obtains recovery of its fixed costs prior to the realization of a return for the delivery utility (i.e., the retailer). Hence, the investors in the retail business are subordinate to the contractual payments due to wholesalers. That is to say, the fixed costs of the wholesaler become operating costs of the retailer. Further, although the Company's POLR III rate plan has been approved by the Commission, there are supply risks that remain due to variations in customer demands, including heating and cooling loads, which are influenced by temperature conditions; switching by customers to alternative providers; and other unforeseen circumstances. POLR service is not a risk-free business. In addition, the Company no longer has control over the supply side of the business, and effectively is a price-taker. Indeed, the loss of diversification that formerly existed within an integrated system has now resulted in a more narrowly defined source of revenues for Duquesne Light. While Duquesne Light has mitigated some of these risks by contracting with an unregulated affiliate through 2007, thereafter the utility could be faced with increased supply risk. With a meaningful proportion of its load made up of commercial and industrial load, the Company has no ability to offset declines in usage and revenues by commercial and industrial customers with off system sales, since it no longer has generation to provide additional revenue. For the Company with relatively high commercial and industrial load, the loss of a diversified revenue stream is potentially problematic. Counter-party risk due to default and/or bankruptcy of the generation suppliers has also developed into a major risk factor. Finally, a delivery-only electric company lacks the risk reducing benefits of economies of scope, control over the planning and operation of both the generation and delivery of electricity, and more diversified sources of revenue. These attributes that are missing from a delivery-only electric company, which elevates its remaining risks. Further, regulatory risk is heightened for a delivery-only electric company due to its single line of business.

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

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next three years (i.e., 2006, 2007 and 2008), the Company's total capital expenditures are expected to be approximately $490 million. These expenditures will represent an approximate 33% ($490 million ÷ $1,497.3 million) increase in net utility plant from the level at December 31, 2005. The Company expects that $347.8 million (or 71%) of these expenditures will require external capital from investors. In the absence of a mechanism to offset erosion of return resulting from the lag in reflecting these investment in rates, it is unlikely the Company will earn its allowed return. A fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital, in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry. In the situation where additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides 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?

A. 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 Duquesne Light to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Electric 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 Electric Group?

A. The Electric Group companies have the following common characteristics: (i) they are listed in the "Electric Utility (East)" section of <u>The Value Line Investment Survey</u>, (ii) their stock is traded on the New York Stock Exchange, (iii) they operate in the Northeastern and Southeastern regions of the U.S., (iv) they are not currently the target of a publicly-announced merger or acquisition, and (v) they do not have a significant amount of electric generation that is unregulated. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company usually does not reflect its underlying fundamentals.

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 Duquesne Light, the Electric Group, and the S&P Public Utilities?

A. For Duquense, its Long Term ("LT") issuer rating is Baa2 from Moody's Investors Service ("Moody's") and the corporate credit rating ("CCR") is BBB from Standard & Poor's Corporation ("S&P"). The LT issuer rating by Moody's and the CCR designation by S&P focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The senior unsecured debt rating of Duquesne Light is BBB- with a negative outlook from S&P. As discussed at length in the testimony of Mr. O'Brien and Ms. Cannell, the rating agencies will be following this rate case closely. Indeed, the outcome of this case will have a direct bearing on the Company's future credit quality ratings. Thus far, the rating agencies have stated:

> "The negative outlook reflects multiple challenges confronting DLH that could result in lower ratings. The ratings could be affected if ... there is a poor outcome in an anticipated rate case. The outlook could be changed to stable when... there is further clarity related to the expected rate case filing in Pennsylvania." **S&P (Research Update: August 10, 2005) *Senior* Unsecured Rating = BBB-/Negative**

> "The rating and stable outlook also consider that the company will be able to recover in its anticipated T&D rate case the approximately $500 to $600 million of planned capital expenditures that are related primarily to transmission and distribution system upgrades."

> "A rating upgrade could be considered if the company ... obtains a reasonable rate outcome in its anticipated transmission and distribution rate case and DLH is able to

> achieve and sustain stronger consolidated credit metrics that would include the percentage ratio of FFO to consolidated debt being in the high teens or higher on a Moody's adjusted basis. DLH's rating could be impacted negatively if the company diverges from its current strategy of repositioning the business around its core regulated electric utility... A rating downgrade could also occur if there is sustained deterioration of its cash flows or an increase in leverage resulting in weaker credit metrics that would include the ratio of FFO to consolidated debt being in the low teens or below." **Moody's (Rating Action: August 4, 2005) Senior Unsecured Rating = Baa3/Stable**
>
> "DLC's planned T&D related capital expenditure program includes $500 million to $600 million over 2005-2007, and should be funded with internal cash flow and equity infusions from the parent, but will require rate base treatment in early 2007."
>
> "Inadequate equity returns from DLC's T&D rate case ...could adversely impact Holdings' ratings." **Fitch Ratings (Rating Action Commentary: April 14, 2005) Senior Unsecured Rating = BBB-/Positive**

For the Electric Group, the average LT issuer rating is A3 from Moody's and the average CCR is BBB+ from S&P. 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 I will subsequently discuss are considered during the rating process. In this regard, the Company's credit quality is weak in comparison with the Electric Group, and the Company's credit rating outlook is negative according to S&P.

Q. How do the financial data compare for Duquesne Light, the Electric 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. The important categories of relative risk may be summarized as follows:

<u>Size.</u> In terms of capitalization, Duquesne Light is smaller than the average size of the Electric Group. The average size of the S&P Public Utilities is much larger than the Electric Group, and the Electric Group is much larger than Duquesne Light. 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. In addition, Duquesne Light serves a concentrated geographic area, and in particular, an urban area that is often more costly to service. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Duquesne Light and the Electric Group.

<u>Market Ratios.</u> 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 Duquesne Light because the Company's stock is not traded. The five-year average price-earnings multiple for the Electric Group was similar to that of the S&P Public Utilities. The five-year average dividend yield was somewhat higher for the Electric Group, as compared to the S&P Public Utilities. The average market-to-book ratio was somewhat higher for the S&P Public Utilities than the Electric Group.

<u>Common Equity Ratio.</u> 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 31.3% for Duquesne Light, 43.3% for the Electric Group, and 37.9% for the S&P Public Utilities. The financial risk for Duquesne Light was higher than that of the Electric Group. Recent initiatives by the Company are intended to rectify the Company's historically low common equity ratio.

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 0.145 (1.7% ÷ 11.7%) for Duquesne Light, 0.264 (2.3% ÷ 8.7%) for the Electric Group, and 0.283 (2.8% ÷ 9.9%) for the S&P Public Utilities. The earnings variability for Duquesne Light was less than that of the Electric Group.

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 83.4% for Duquesne Light, 88.3% for the Electric Group, and 84.8% for the S&P Public Utilities. The operating risk for Duquesne Light is fairly similar to the Electric Group, and the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) 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 2.71 times for Duquesne Light, 2.66 times for the Electric Group, and 2.56 times for the S&P Public Utilities. Coverage for Duquesne Light was fairly similar to that of the Electric Group. Interest coverages for Duquesne Light were influenced by floating rate debt.

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 Duquesne Light, the Electric Group, and the S&P 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. Historically, the five-year average percentage of IGF to capital expenditures was 142.1% for Duquesne Light, 125.0% for the Electric Group, and

107.1% for the S&P Public Utilities. The cash flow for Duquesne Light was somewhat stronger than that of the Electric Group due to the collection by Duquesne Light of the CTC revenues during the years 2000 through 2002.

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 .74 as the average for the Electric 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 73% (.74 ÷ 1.01) for the Electric Group, using the S&P Public Utilities' average beta as a benchmark.

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

A. The risk of Duquesne Light parallels that of the Electric Group in certain respects with regard to historical financial performance. However, Duquesne Light has a higher credit risk, as evidenced by its lower bond ratings. In this regard, the rating outlook on the Company's rating is negative according to S&P. Also, the size of the Company is smaller than the average size of the Electric Group. While the cost of equity can be estimated from the market data for the Electric Group, the results from the Electric Group would tend to understate the Company's cost of equity, because the Company is more risky.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for Duquesne Light.

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

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents Duquesne Light's capitalization and related capital structure at December 31, 2005, the end of the historic test year.[1] Also shown on Schedule 5 is the Duquesne Light's estimated capital structure at December 31, 2006, the end of the future test year. During the future test year, the changes in the Company's capital structure are projected to include: (i) the remarketing of $43.155 million of tax-exempt debt; (ii) a $27,562,500 equity infusion from its Parent Company, which was approved by the Commission in settlement of an Informal Investigation at Docket M-00051929; and (iii) the Company's projection of retained earnings at December 31, 2006. The equity infusions in the future test year will

[1] For both the historic and future test year, preference stock has been excluded because it is related to the Employee Stock Ownership Plan ("ESOP") that is unrelated to the financing of the rate base.

help strengthen the Company's common equity ratio given its substantial capital expenditures for infrastructure construction going forward.

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 or refunding of high cost long-term debt. The second adjustment relates to accumulated Other Comprehensive Income ("OCI").

Q. Please describe the first adjustment.

A. I have adjusted the principal amounts 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 Duquesne Light 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, Duquesne Light'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 Duquesne Light 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 Duquesne Light 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 majority of the accumulated OCI for the Company has its roots in the MPL, while the loss on securities available for sale represents a minor portion of the accumulated OCI. Duquesne Light holds shares of the Parent Company common stock in conjunction with its employee benefit plans. 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. The unrealized loss on the Company's investment in DLH stock should also be eliminated. Hence, the accumulated OCI must be excluded from the common equity.

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

A. Yes. Although, there was no short-term debt outstanding at December 31, 2005, the Company projects short-term debt in the future test year for the purpose of financing its construction work in progress ("CWIP"). Given the Company's procedure of calculating its AFUDC rate by including short-term interest expense in the calculation, it has been the Commission's policy to exclude short-term debt from the capital structure for ratesetting purposes.

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

A. Since ratemaking is prospective, the rate of return should reflect known changes that will occur during the course of the future test year, at a minimum, and should consider conditions that will exist during the period of time the proposed rates will be effective. As a result, I will adopt the Company's future test year-end capital structure ratios of 43.10% long-term debt, 9.06% preferred stock, and 47.85% 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 and they are appropriate so that the Company can strive to improve its bond ratings.

COST OF SENIOR CAPITAL

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

A. Consistency with the capital structure ratios for the Company requires that the embedded cost rates of Duquesne Light's senior securities must also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in prior Duquesne Light rate cases. 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 7.01% at December 1, 2005. By December 31, 2006, the embedded debt cost rate is estimated to be 6.90%, as shown on page 2 of Schedule 6. The future test year cost of long-term debt reflects the estimated cost for the remarketing of the $43.155 million of tax-exempt debt. While exempt for ordinary income tax purposes, the interest income to the holder is subject to the alternative minimum tax ("AMT") on two of the three issues. As such, the estimated cost for the remarketing of this debt includes a fixed rate of 5.50% (at the upper end of the range) as provided by Lehman Brothers, plus 0.25% related to the AMT feature. The lower rate applies on one of the issues (i.e., non-ATM) and the higher rate applies to the other two issues (i.e., AMT). 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"), used on page 3 of Schedule 6 is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 6.90% embedded cost of long-term debt at December 31, 2006, as shown on page 2 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 43.10% long-term debt ratio. In my calculation of the embedded cost of long-term debt, I have recognized the costs associated with the Company's early redemption of high cost debt. As previously explained, it is necessary to compensate Duquesne Light for the costs incurred to lower the embedded debt cost rate which reduces the cost of capital charged to ratepayers. The amortization of gains on long-term debt has also been reflected as part of these costs.

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

A. For the future test year, I have calculated a 5.37% embedded cost of preferred stock as shown on page 2 of Schedule 7. I will adopt the 5.37% embedded cost of preferred stock, which is related to the 9.06% preferred stock ratio shown on Schedule 5. The details regarding the individual cost rates for each series of preferred stock are provided on page 3 of Schedule7.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for Duquesne Light.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among Duquesne Light, the Electric 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 Electric 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 dated January 10, 2002 for Pennsylvania-American Water Company at Docket No. R-00016339, dated August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750, dated January 29, 2004 for Pennsylvania-American Water Company at Docket No. R-00038304 (affirmed by the Commonwealth Court on November 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 January 2006, the monthly dividend yields of the Electric Group are shown graphically on Schedule 8. The monthly dividend yields shown on Schedule 8 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price 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 January 2006, the average dividend yield was 4.44% for the Electric 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 4.53% and 4.56%, respectively, for the Electric Group. I have used, for the purpose of my direct testimony, a dividend yield of 4.53% for the Electric 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 4.36% in July 2005 to 4.64% in December 2005 and then declining to 4.48% in January 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 Electric 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 4.66% for the Electric 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 the 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 Electric 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 and insurance costs 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) and insurance costs. 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 October 10, 2005 issue of Blue Chip, those forecasts are:

Blue Chip Economic Indicators

Year	Nominal GDP	Corporate Profits, Pretax
2007	5.5%	5.1%
2008	5.5%	5.5%
2009	5.4%	5.4%
2010	5.5%	6.5%
2011	5.4%	5.9%
Averages		
2007-11	5.5%	5.7%
2012-16	5.5%	6.0%

These forecasts show that growth in corporate profits will generally exceed growth in overall GDP. It is also indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[2] From these data, growth in corporate profits of about 6% would represent an overall benchmark for the long-term growth component of the DCF.

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

A. I have considered the growth in the financial variables shown on Schedules 9 and 10. The bar graph provided on Schedule 9 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 Electric Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 9, the historical average earnings per share growth rates have been negative to 4.50% for the Electric Group.

Schedule 10 provides projected earnings per share growth rates taken from

[2] Obviously, growth in corporate profits are negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since the 1934. .

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 10 for the Electric Group.

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

A. As to the five-year forecast growth rates, Schedule 10 indicates that the projected earnings per share growth rates for the Electric Group are 4.40% by IBES/First Call, 5.08% by Zacks, 4.29% by Reuters/MarketGuide, and 4.39% by Value Line. The Value Line projections indicate that earnings per share for the Electric Group will grow prospectively at a more rapid rate (i.e., 4.39%) than the dividends per share (i.e., 3.94%), 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 Electric 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.[3] 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

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[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould.

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 4.29% to 5.08%. To those company-specific growth rates, consideration must be given to the 6% 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 0.43% (9.66% - 10.09%) for the Electric 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 Duquesne Light?

A. No. The DCF returns that are produced for the Electric Group relate to the average size of that group. As noted previously, Duquesne Light is considerably smaller than the average size of the Electric Group. In order to provide some recognition of the additional return that is required to compensate Duquesne Light 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% (6.02% - 5.71%) for the six-months ended January 2006. This yield difference can be added to the DCF calculation for the Electric Group to provide some recognition of the higher risk of Duquesne Light 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 additional risk of Duquesne Light 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_1/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:

	D_1/P_0	+	g	+	$lev.$	=	k	+	$size$	=	K
Electric Group	4.66%	+	5.00%	+	0.43%	=	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 equity premium.

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 11. For the twelve months ended January 2006, the average monthly yield on Moody's A-rated index of public utility bonds was 5.65%. For the six and three-month periods ending January 2006, the yields were 5.71% and 5.81%, 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, November 10, 2004, December 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 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 February 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:

		Corporate		20-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2006	First	5.5%	6.4%	4.8%	1.0%	5.8%
2006	Second	5.7%	6.7%	5.0%	1.0%	6.0%
2006	Third	5.9%	6.8%	5.1%	1.0%	6.1%
2006	Fourth	5.9%	6.9%	5.1%	1.0%	6.1%
2007	First	6.0%	6.9%	5.1%	1.0%	6.1%
2007	Second	5.9%	6.9%	5.1%	1.0%	6.1%

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:

	Blue Chip Financial Forecasts				
	Corporate		20-Year	A-rated Public Utility	
Year	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2007	6.2%	7.1%	5.4%	1.0%	6.4%
2008	6.2%	7.1%	5.4%	1.0%	6.4%
2009	6.3%	7.1%	5.5%	1.0%	6.5%
2010	6.3%	7.2%	5.5%	1.0%	6.5%
2011	6.4%	7.2%	5.6%	1.0%	6.6%
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 Electric 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 12 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 12 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 H. 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 12, 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 Electric 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 Electric 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 Electric 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:

	i	+	RP	=	k	+	*Credit Quality*	=	K
Electric Group	6.50%	+	5.00%	=	11.50%	+	0.31%	=	11.81%

The adjustment for credit quality rests with Duquense's Baa2/BBB rating as compared to the yield on A-rated public utility bonds. This means that the Risk Premium cost rate shown above would understate the Company's cost of equity without the credit quality adjustment.

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 I. 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 I. 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 Electric 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 13, the average beta is .74 for the Electric 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:

$$\beta l = \beta u \, [1 + (1 - t) \, D/E + P/E]$$

where βl = the leveraged beta, βu = 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 .47 for the Electric Group if they employed no leverage and were 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of .82 for the Electric 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 13, I provided the historical yields on 20-year Treasury bonds. For the twelve months ended January 2006, the average yield was 4.64%, as shown on page 3 of that schedule. For the six- and three-months ended January 2006, the yields on 20-year Treasury bonds were 4.67% and 4.74%, respectively. As shown on page 4 of Schedule 13, forecasts published by Blue Chip on February 1, 2006 indicate that the yields on long-term Treasury bonds are expected to 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 I, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 5.92%). The resulting market premium is 6.21% (6.5% + 5.92% = 12.42% ÷ 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 edition, page 623). 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, Electric Group has an average market capitalization of its equity of $2,673 million, which would place it in the fourth decile consisting of companies with market capitalization between $2,232 million and $3,464 million according to the size of the companies traded on the NYSE, AMEX, and NASDAQ. The third through fifth deciles comprise the mid-cap group of stocks. 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 Electric Group. Of course, the size adjustment would be even greater for Duquesne

Light because the market cap of its Parent Company is just $1,451 million, and thus would be in the "low-cap" category. The "low-cap" size premium is 1.81% for CAPM purposes, thus showing the conservative nature of the size adjustment I employed for the Electric 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 .82 for the Electric Group, the 6.21% market premium, and the size premium adjustment developed previously, the following result is indicated.

	Rf	+	β	x (	$Rm\text{-}Rf$	) +	$size$	=	K
Electric Group	5.50%	+	0.82	x (	6.21%	) +	0.95%	=	11.54%

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 J. 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 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 J for definitions) of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric 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 14.

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 on page 2 of Schedule 14 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 16.7% using the median value as shown on page 2 of Schedule 14. The forecast rates of return as published by Value Line are shown by the 15.5% 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:

	Historical	*Forecast*	*Average*
Comparable Group Companies	16.70%	15.50%	16.10%

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

Q. What credit quality issues should be considered in this case for Duquesne Light?

A. As discussed at length in Ms. Cannell's testimony, the Company's credit quality ratings are at risk. Indeed, as noted earlier, the credit rating agencies are closely motoring the outcome of this case. In addition, Duquesne Light carries a business profile score of '4,' which is within the categories of '1' (excellent) to '10' (vulnerable). Within the group of regulated transmission and distribution utilities (electric, gas and water), most business profile scores are clustered in the '1,' '2,' '3' and '4' categories. The average business profile score for the Electric Group is '3.' As such, Duquesne Light requires stronger financial metrics in order to attain reasonable credit quality.

As noted previously, Duquesne Light's rating is Baa2/BBB and the rating on its debt in BBB-. This places the Company's debt at the bottom of the investment grades (i.e., Baa/BBB). 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 both nationally recognized credit rating agencies. Due to its weak credit rating, the Company should be provided with an opportunity to experience a rate of return that is supportive of stronger credit quality.

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%, with a midpoint of 11.50%. The Company requested the high end of the cost of equity range to provide recognition of the quality of its service as explained in the testimony of Mr. Morgan O'Brien. Such cost rate will accommodate to the Company's high risk traits including its lower credit quality as shown by its Baa2/BBB bond rating, its small size, and its business risk characteristics, including a high percentage of sales/deliveries to industrial and commercial customers, and its infrastructure needs. 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.

DUQUESNE LIGHT COMPANY

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 sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Except and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial	National Society of

	Forum	Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

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

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

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.

<u>DISCOUNTED CASH FLOW ANALYSIS</u>

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $100. $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> 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, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp. In this circumstance:

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

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

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

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

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

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

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

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

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, Ks is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which 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

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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.

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

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 x .75 = \$0.75, and \$1.00 - \$0.75 = \$0.25 ÷ \$8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield (\$0.75 ÷ \$12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., \$0.75 ÷ \$8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. 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.

Dividend Yield

The historical annual dividend yields are shown on and Schedule 3 for the Electric Group. The 2000-2004 five-year average dividend yield was 4.8% for the Electric Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 8. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs 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:

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

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.500% (5.00% x .5) for the Electric 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 4.64% (4.53% x 1.02500) for the Electric Group.

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

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

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.67% (4.53% x 1.03106) for the Electric Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

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

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

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

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

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 1.1325% (4.53% ÷ 4) for the Electric Group. The compound dividend yield would be 4.67% (1.011464^4-1) for the Electric 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 Electric Group, a 4.66% forward-looking dividend yield is the average (4.64% + 4.67% + 4.67% = 13.98% ÷ 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 growth using company-specific variables.

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.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is <u>The Value Line Investment Survey</u> which contains estimated future projections of growth. <u>The Value Line Investment Survey</u> provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics 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

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[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. 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 example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*B*x*R*" shown on Schedule 10. 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. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

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 Electric 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:

	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	44.84%	50.52%
Preferred Stock	1.79	2.41
Common Equity	53.37	47.07
Total	100.00%	100.00%

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:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D\ /\ E) - (ku - d)\ P\ /\ E$$

$$8.23\% = 9.66\% - (((8.23\%-5.71\%)\ .65)\ 44.84\%/53.37\%) - (8.23\% - 6.26\%)\ 1.79\%/53.37\%$$

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 8.23% in the case of the Electric 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.

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$10.09\% = 8.23\% + (((8.23\% - 5.71\%).65)\ 50.52\%/47.07\%) + (8.23\% - 6.26\%)\ 2.41\%/47.07\%$$

APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

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 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 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%.

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 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. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 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:

> "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 seniment 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). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 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 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 11 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 11. 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 11, 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 11, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.01 percentage points for the twelve-months ended January 2005. For the six- and three-month periods ending January 2005, the yield spread was 1.04% and 1.07%, 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 13 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, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

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

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

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

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

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.78%	5.27%
Geometric Mean	4.14%	3.18%
Median	8.94%	6.95%
Midpoint of Range	6.54%	5.07%
Average	6.16%	5.17%

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 12 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 12.

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 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 *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

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

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

Page 1 of Schedule 13 provides the 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.

<u>Market Premium</u>

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. 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 January 13, 2006, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 13) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of January 13, 2006	1.6%	+	8.78%[1]	=	10.38%

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 12.46%.

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.90%	(	1.05230	)	+	10.46%	=	12.46%

where:	Price (P)	at	31-Jan-2006	=	1280.08
	Dividend (D)	for	4th Qtr '05	=	6.08
	Dividend (D)		annualized	=	24.32
	Growth (g)		First Call EpS	=	10.46%

Using these indicators, the total market return is 11.42% (10.38% + 12.46% = 22.84% ÷ 2) using both the Value Line and S&P derived returns. With the 11.42% forecast market return and the 5.50% risk-free rate of return, a 5.92% (11.42% - 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 13. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 13, 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

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

For the CAPM, a market premium of 6.21% (6.5% + 5.92% = 12.42% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 5.92% using forecasts.

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.

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.

DUQUESNE LIGHT COMPANY

EXHIBIT

TO ACCOMPANY

THE DIRECT TESTIMONY

OF

PAUL R. MOUL

CONCERNING
RATE OF RETURN

Exhibit PRM-1

<u>Duquesne Light Company</u>
Index of Schedules

Duquesne Light Company
Proposed Rate of Return
Estimated at December 31, 2006

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.03%	6.90%	2.97%
Preferred Stock	9.04%	5.37%	0.49%
Common Equity	47.93%	11.75%	5.63%
Total	100.00%		9.09%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a 41.4935% composite federal and state income tax rate (13.43% ÷ 2.97%)	4.52 x
Post-tax coverage of interest expense (9.09% ÷ 2.97%)	3.06 x
Post-tax coverage of interest expense and preferred stock dividends (9.09% ÷ 3.46%)	2.63 x

Duquesne Light Company
Capitalization and Financial Statistics
2000-2004, Inclusive

	2004	2003	2002	2001	2000	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,633.7	$ 1,508.0	$ 1,700.3	$ 1,815.3	$ 1,833.6	
Short-Term Debt	$ -	$ -	$ -	$ -	$ -	
Total Capital	*$ 1,633.7*	*$ 1,508.0*	*$ 1,700.3*	*$ 1,815.3*	*$ 1,833.6*	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	58.5%	60.2%	65.3%	66.9%	66.6%	63.5%
Preferred Stock	8.9%	4.6%	4.1%	4.1%	3.9%	5.1%
Common Equity	32.5%	35.2%	30.6%	29.0%	29.4%	31.3%
	99.9%	100.0%	100.0%	100.0%	99.9%	100.0%
Based on Total Capital:						
Total Debt, incl. Short Term	58.5%	60.2%	65.3%	66.9%	66.6%	63.5%
Preferred Stock	8.9%	4.6%	4.1%	4.1%	3.9%	5.1%
Common Equity	32.5%	35.2%	30.6%	29.0%	29.4%	31.3%
	99.9%	100.0%	100.0%	100.0%	99.9%	100.0%
Rate of Return on Book Common Equity	11.5%	12.6%	13.8%	9.4%	11.0%	11.7%
Operating Ratio (1)	*81.0%*	*80.8%*	*82.7%*	*88.4%*	*84.1%*	*83.4%*
Coverage incl. AFUDC (2)						
Pre-tax: All Interest Charges	3.43 x	2.90 x	2.78 x	2.12 x	2.33 x	2.71 x
Post-tax: All Interest Charges	2.47 x	2.15 x	2.08 x	1.71 x	1.86 x	2.05 x
Overall Coverage: All Int. & Pfd. Div.	2.16 x	2.04 x	1.98 x	1.63 x	1.80 x	1.92 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	3.43 x	2.90 x	2.77 x	2.12 x	2.31 x	2.71 x
Post-tax: All Interest Charges	2.47 x	2.15 x	2.06 x	1.70 x	1.84 x	2.04 x
Overall Coverage: All Int. & Pfd. Div.	2.16 x	2.04 x	1.97 x	1.63 x	1.77 x	1.91 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	1.2%	1.1%	2.8%	1.0%
Effective Income Tax Rate	39.5%	39.5%	39.5%	37.0%	35.0%	38.1%
Internal Cash Generation/Construction (4)	107.9%	75.0%	166.3%	408.1%	-46.8%	142.1%
Gross Cash Flow/ Avg. Total Debt(5)	17.9%	12.9%	16.2%	24.4%	14.6%	17.2%
Gross Cash Flow Interest Coverage(6)	4.37 x	2.91 x	3.45 x	4.75 x	3.61 x	3.82 x
Common Dividend Coverage (7)	2.17 x	1.78 x	2.78 x	5.58 x	0.85 x	2.63 x

See Page 2 for Notes.

Duquesne Light Company.
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

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

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

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

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

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

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

Source of Information: Company provided data

Electric Group
Capitalization and Financial Statistics (1)
2000-2004, Inclusive

	2004	2003	2002	2001	2000	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 4,846.8	$ 4,722.8	$ 4,630.8	$ 3,764.0	$ 3,663.2	
Short-Term Debt	$ 116.0	$ 149.6	$ 190.2	$ 198.1	$ 316.3	
Total Capital	$ 4,962.8	$ 4,872.4	$ 4,821.0	$ 3,962.1	$ 3,979.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	16 x	16 x	12 x	12 x	15 x
Market/Book Ratio	146.6%	137.7%	136.3%	137.9%	136.1%	138.9%
Dividend Yield	4.5%	4.8%	4.7%	4.9%	5.3%	4.8%
Dividend Payout Ratio	74.5%	78.1%	92.8%	54.0%	58.9%	71.7%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	52.5%	54.2%	56.5%	53.5%	52.6%	53.8%
Preferred Stock	2.4%	2.1%	2.4%	3.6%	4.0%	2.9%
Common Equity	45.2%	43.7%	41.1%	42.9%	43.5%	43.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.3%	55.2%	57.5%	55.1%	56.4%	55.5%
Preferred Stock	2.4%	2.0%	2.4%	3.5%	3.6%	2.8%
Common Equity	44.4%	42.8%	40.1%	41.4%	39.9%	41.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	9.2%	9.5%	9.2%	4.7%	10.9%	8.7%
Operating Ratio (2)	88.6%	88.2%	87.9%	89.9%	87.0%	88.3%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.87 x	2.70 x	2.71 x	2.23 x	2.90 x	2.68 x
Post-tax: All Interest Charges	2.22 x	2.11 x	2.09 x	1.74 x	2.13 x	2.06 x
Overall Coverage: All Int. & Pfd. Div.	2.18 x	2.05 x	2.02 x	1.63 x	2.04 x	1.98 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.84 x	2.67 x	2.69 x	2.21 x	2.88 x	2.66 x
Post-tax: All Interest Charges	2.19 x	2.08 x	2.08 x	1.72 x	2.12 x	2.04 x
Overall Coverage: All Int. & Pfd. Div.	2.14 x	2.02 x	2.00 x	1.62 x	2.02 x	1.96 x
Quality of Earnings & Cash Flow						
AFUDC/Income Avail. for Common Equity	3.2%	3.8%	1.6%	-21.5%	-18.0%	-6.2%
Effective Income Tax Rate	32.2%	33.8%	36.3%	43.1%	-390.8%	-49.1%
Internal Cash Generation/Construction (4)	118.2%	110.4%	111.8%	131.8%	152.6%	125.0%
Gross Cash Flow/ Avg. Total Debt(5)	21.0%	19.0%	18.7%	19.7%	20.4%	19.8%
Gross Cash Flow Interest Coverage(6)	4.18 x	3.67 x	3.53 x	3.75 x	3.60 x	3.75 x
Common Dividend Coverage (7)	4.59 x	4.47 x	4.39 x	5.53 x	4.75 x	4.75 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.

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

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

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

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

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) as a percentage of average total debt.

(7) Gross Cash Flow plus interest charges divided by interest charges.

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

Basis of Selection

The Electric Group includes companies that (i) they are listed in the "Electric Utility (East)" section of The Value Line Investment Survey, (ii) their stock is traded on the New York Stock Exchange, (iii) they operate in the Northeastern and Southeastern regions of the U.S., (iv) they are not currently the target of a publicly-announced merger or acquisition, and (v) they do not have a significant amount of electric generation that is unregulated.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
CHG	CH Energy Group	A2	A	NYSE	A-	0.80
CV	Central Vermont P.S.	-	BB+	NYSE	B	0.55
ED	Consolidated Edison	A1	A	NYSE	B+	0.60
DQE	Duquesne Light Holding:	Baa2	BBB	NYSE	B	0.80
EAS	Energy East Corp.	Baa1	BBB+	NYSE	B+	0.85
GMP	Green Mountain Power	Baa1	BBB	NYSE	B	0.60
NU	Northeast Utilities	Baa1	BBB	NYSE	B	0.80
NST	NSTAR	A1	A	NYSE	B+	0.75
POM	Pepco Holdings	Baa1	BBB+	NYSE	B	0.90
	Average	A3	BBB+		B+	0.74

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
2000-2004, Inclusive

	2004	2003	2002	2001	2000	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,204.1	$ 14,494.4	$14,111.6	$ 13,848.1	$11,801.3	
Short-Term Debt	$ 274.2	$ 259.4	$ 936.6	$ 1,195.1	$ 1,649.0	
Total Capital	$ 14,478.3	$ 14,753.8	$15,048.2	$ 15,043.2	$13,450.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	13 x	15 x	17 x	18 x	16 x
Market/Book Ratio	181.7%	147.9%	153.9%	194.3%	188.8%	173.3%
Dividend Yield	3.7%	4.0%	4.8%	3.9%	4.7%	4.2%
Dividend Payout Ratio	69.5%	59.6%	72.8%	61.6%	82.6%	69.2%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	59.2%	61.1%	61.7%	58.8%	57.5%	59.7%
Preferred Stock	1.9%	1.9%	2.5%	3.0%	2.7%	2.4%
Common Equity	38.9%	36.9%	35.8%	38.2%	39.8%	37.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	60.6%	62.5%	64.6%	62.8%	63.0%	62.7%
Preferred Stock	1.9%	1.9%	2.4%	2.7%	2.4%	2.3%
Common Equity	37.5%	35.6%	33.1%	34.5%	34.6%	35.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	10.5%	9.7%	6.9%	14.2%	8.3%	9.9%
Operating Ratio (2)	82.2%	84.6%	85.1%	85.5%	86.8%	84.8%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.86 x	2.49 x	2.28 x	2.81 x	2.55 x	2.60 x
Post-tax: All Interest Charges	2.30 x	2.05 x	1.89 x	2.19 x	2.01 x	2.09 x
Overall Coverage: All Int. & Pfd. Div.	2.27 x	2.02 x	1.85 x	2.14 x	1.95 x	2.05 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.83 x	2.45 x	2.23 x	2.78 x	2.52 x	2.56 x
Post-tax: All Interest Charges	2.27 x	2.01 x	1.85 x	2.15 x	1.98 x	2.05 x
Overall Coverage: All Int. & Pfd. Div.	2.24 x	1.98 x	1.81 x	2.10 x	1.92 x	2.01 x
Quality of Earnings & Cash Flow						
AFUDC/Income Avail. for Common Equity	2.2%	1.5%	2.6%	2.0%	5.3%	2.7%
Effective Income Tax Rate	26.4%	41.5%	29.3%	30.6%	35.6%	32.7%
Internal Cash Generation/Construction (4)	130.7%	128.7%	93.0%	95.9%	87.0%	107.1%
Gross Cash Flow/ Avg. Total Debt(5)	19.2%	19.3%	17.4%	17.7%	17.7%	18.3%
Gross Cash Flow Interest Coverage(6)	4.16 x	4.19 x	3.86 x	3.58 x	3.58 x	3.87 x
Common Dividend Coverage (7)	5.95 x	5.65 x	4.34 x	4.56 x	4.28 x	4.96 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities (1)

	Ticker	Credit Rating (2) Moody's	Credit Rating (2) S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Ba1	BB-	NYSE	A-	1.60
Ameren Corporation	AEE	A2	A-	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB+	NYSE	B+	1.20
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.65
CINergy Corp.	CIN	Baa1	BBB+	NYSE	B	0.85
CMS Energy	CMS	Ba1	BB	NYSE	B	1.45
Consolidated Edison	ED	A1	A+	NYSE	A-	0.60
Constellation Energy Group	CEG	A2	A-	NYSE	A-	0.95
DTE Energy Co.	DTE	Baa1	BBB+	NYSE	B+	0.70
Dominion Resources	D	A3	A-	NYSE	B	0.90
Duke Energy	DUK	A3	A-	NYSE	A-	1.15
Edison Int'l	EIX	Ba3	BB	NYSE	B	1.05
El Paso Corp.	EP	B1	BB	NYSE	B+	2.00
Entergy Corp.	ETR	Baa3	BBB	NYSE	B	0.80
Exelon Corp.	EXC	A3	A-	NYSE	B	0.75
FPL Group	FPL	A1	A	NYSE	B+	0.75
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B+	0.85
Kinder Morgan	KMI	Baa2	BBB	NYSE	B	0.90
NICOR Inc.	GAS	Aa2	AA	NYSE	B+	1.10
NiSource Inc.	NI	Baa2	BBB	NYSE	A	0.80
PG&E Corp.	PCG	Caa2	D	NYSE	B	1.10
PPL Corp.	PPL	Baa1	A-	NYSE	B+	1.00
Peoples Energy	PGL	Aa3	A-	NYSE	B+	0.85
Pinnacle West Capital	PNW	Baa1	BBB	NYSE	A-	0.90
Progress Energy, Inc.	PGN	Baa1	BBB+	NYSE	A-	0.85
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.90
Sempra Energy	SRE	A2	A+	NYSE	NR	1.00
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	A2	BBB	NYSE	A	0.95
TXU CORP	TXU	Baa3	BBB	NYSE	B	1.00
Williams Cos.	WMB	Caa1	B+	NYSE	B	2.65
Xcel Energy Inc	XEL	Baa1	BBB+	NYSE	B+	0.80
Average for S&P Utilities		Baa2	BBB		B+	1.01

Note: * (1) Includes companies contained in S&P Utility Compustat. AES Corp., Calpine Corp., and Dynegy, Inc. are not included.
(2) Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Duquesne Light Company
Capitalization and Related Capital Structure Ratios
Actual at December 31, 2005 and Estimated at December 31, 2006

	Actual at December 31, 2005			Estimated at December 31, 2006		
	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt
Long-Term Debt[1]	$ 589,144,535	42.64%	42.64%	$ 634,801,775 [3]	43.03%	42.27%
Preferred Stock	133,434,357	9.66%	9.66%	133,434,357	9.04%	8.89%
Common Equity						
Capital Surplus	571,117,012			598,679,512 [4]		
Retained earnings[2]	88,071,262			108,319,996 [5]		
Total Common Equity	659,188,274	47.71%	47.71%	706,999,508	47.93%	47.08%
Total Permanent Capital	1,381,767,166	100.00%	100.00%	1,475,235,640	100.00%	98.24%
Short-term Debt	-		0.00%	26,395,000		1.76%
Total Capital Employed	$ 1,381,767,166		100.00%	$ 1,501,630,640		100.00%

Notes: (1) Includes current portion of long-term debt.
(2) Excluding Accumulated Other Comprehensive Income, related to:

Unrealized loss on DLH stock	$ 2,829,540
Minimum pension liability ("MPL")	23,643,848
Total at December 31, 2005	$ 26,473,388
Unrealized loss on DLH stock	$ 2,829,540
Minimum pension liability ("MPL")	22,034,866
Total at December 31, 2006	$ 24,864,406

(3) Reflects changes in the principal amount of long-term debt as follows:

Date	Series	Amount
11/01/06	Ohio Water 1999 Series B due 3/31/31 (AMT)	$ 13,500,000
11/01/06	Ohio AIR 1999 Series C due 3/01/31 (non-AMT)	$ 4,655,000
11/01/06	Beaver County 1999 Series A due 4/01/31 (AMT)	25,000,000
	Total	$ 43,155,000

(4) Reflects capital contribution form Parent Company of: $ 27,562,500
(5) Projection provided by the Company of a build-up of retained earnings of: $ 20,248,734

Source of Information: Company provided data

Duquesne Light Company

Calculation of the Embedded Cost of Long-Term Debt

Actual at December 31, 2005

Series		Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate	Weighted Cost Rate [2]
First Mortgage Bonds					
6.700% FMB due 04/30/32	$	100,000,000	15.68%	6.95%	1.09%
5.700% FMB due 05/15/14		200,000,000	31.35%	5.80%	1.82%
6.450% FMB due 02/27/08		40,000,000	6.27%	6.54%	0.41%
6.700% FMB due 04/15/12		200,000,000	31.35%	6.79%	2.13%
					0.00%
Pollution Control Revenue Bonds					0.00%
Allegheny County 1999					
Series B due 09/01/11		47,925,000	7.51%	4.13%	0.31%
Allegheny County 1999					
Series A due 12/01/13		50,000,000	7.84%	4.39%	0.34%
Total Long -Term Debt		637,925,000	100.00%		6.10%
Unamortized Call Premium		(48,780,465)			
Long Term- Debt	$	589,144,535			
Annualized Cost	$	38,920,646			
Amortization of Gain on Reacquired Debt		(119,667)			
Amortization of Loss on Reacquired Debt		2,501,981			
Total Cost	$	41,302,960			7.01%

Notes: [1] Includes current portion of long-term debt.
[2] As calculated on page 3 of this schedule.

Source of Information: Company provided data

Duquesne Light Company

Calculation of the Embedded Cost of Long-Term Debt
Estimated at December 31, 2006

Series	Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate	Weighted Cost Rate [2]
First Mortgage Bonds				
6.700% FMB due 04/30/32	$ 100,000,000	14.68%	6.95%	1.02%
5.700% FMB due 05/15/14	200,000,000	29.37%	5.80%	1.70%
6.450% FMB due 02/27/08	40,000,000	5.87%	6.54%	0.38%
6.700% FMB due 04/15/12	200,000,000	29.37%	6.79%	1.99%
				0.00%
Pollution Control Revenue Bonds				0.00%
Allegheny County 1999 Series B due 09/01/11	47,925,000	7.04%	4.13%	0.29%
Allegheny County 1999 Series A due 12/01/13	50,000,000	7.34%	4.39%	0.32%
Ohio Water 1999 Series B due 3/31/31 (AMT)	13,500,000	1.98%	5.85%	0.12%
Ohio AIR 1999 Series C due 3/01/31 (non-AMT)	4,655,000	0.68%	5.68%	0.04%
Beaver County 1999 Series A due 4/01/31 (AMT)	25,000,000	3.67%	5.83%	0.21%
Total Long -Term Debt	681,080,000	100.00%		6.08%
Unamortized Call Premium	(46,278,225)			
Long Term- Debt	$ 634,801,775			
Annualized Cost	$ 41,431,969			
Amortization of Gain on Reacquired Debt	(119,667)			
Amortization of Loss on Reacquired Debt	2,502,240			
Total Cost	$ 43,814,542			6.90%

Notes: [1] Includes current portion of long-term debt.
[2] As calculated on page 3 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Effective Cost of Long-Term Debt by Series
Actual at December 31, 2005

Series	Coupon Rate	Date of Issue	Date of Maturity	Average Term in Years [1]	Principal Amount Outstanding	Premium/ Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [2]
First Mortgage Bonds									
6.700% FMB due 04/30/32	6.70%	04/30/02	04/30/32	30.0	$ 100,000,000	$3,150,000	$ 96,850,000	96.85%	6.95%
5.700% FMB due 05/15/14	5.70%	05/18/04	05/15/14	10.0	200,000,000	1,524,000	198,476,000	99.24%	5.80%
6.450% FMB due 02/27/08	6.45%	02/27/98	02/27/08	10.0	40,000,000	250,000	39,750,000	99.38%	6.54%
6.700% FMB due 04/15/12	6.70%	04/15/02	04/15/12	10.0	200,000,000	1,300,000	198,700,000	99.35%	6.79%
Pollution Control Revenue Bonds									
Allegheny County 1999 Series B due 09/01/11	4.050%	11/18/99	09/01/11	11.8	47,925,000	348,772	47,576,228	99.27%	4.13%
Allegheny County 1999 Series A due 12/01/13	4.350%	11/18/99	12/01/13	14.0	50,000,000	210,987	49,789,013	99.58%	4.39%
Ohio Water 1999 Series B due 3/31/31 (AMT)	5.750%	11/01/06	03/01/31	24.3	13,500,000	176,250	13,323,750	98.69%	5.85%
Ohio AIR 1999 Series C due 3/01/31 (non-AMT)	5.500%	11/01/06	03/01/31	24.3	4,655,000	109,913	4,545,088	97.64%	5.68%
Beaver County 1999 Series A due 4/01/31 (AMT)	5.750%	11/01/06	04/01/31	24.4	25,000,000	262,500	24,737,500	98.95%	5.83%

Notes: [1] Determined by taking into account the effect the annual sinking fund requirements which are met by the retirement of bonds which reduce the term of each issue.
[2] The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Embedded Cost of Preferred Stock
Actual at December 31, 2005

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate [1]
3.75% Series	$ 7,407,400	5.46%	3.78%	0.21%
4.00% Series	27,485,450	20.27%	3.34%	0.68%
4.10% Series	6,012,178	4.43%	4.14%	0.18%
4.15% Series	6,643,559	4.90%	4.18%	0.20%
4.20% Series	5,021,000	3.70%	4.24%	0.16%
6.50% Series	75,000,000	55.31%	6.67%	3.69%
$2.10 Series	8,038,542	5.93%	4.23%	0.25%
	$ 135,608,129	100.00%		5.37%
Less: Preferred Stock Expense	2,173,772			
Total Preferred Stock	$ 133,434,357			

Notes: [1] As calculated on page 3 of this schedule.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Embedded Cost of Preferred Stock
Estimated at December 31, 2006

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate [1]
3.75% Series	$ 7,407,400	5.46%	3.78%	0.21%
4.00% Series	27,485,450	20.27%	3.34%	0.68%
4.10% Series	6,012,178	4.43%	4.14%	0.18%
4.15% Series	6,643,559	4.90%	4.18%	0.20%
4.20% Series	5,021,000	3.70%	4.24%	0.16%
6.50% Series	75,000,000	55.31%	6.67%	3.69%
$2.10 Series	8,038,542	5.93%	4.23%	0.25%
	$ 135,608,129	100.00%		5.37%
Less: Preferred Stock Expense	2,173,772			
Total Preferred Stock	$ 133,434,357			

Notes: [1] As calculated on page 3 of this schedule.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Effective Cost of Preferred Stock by Series

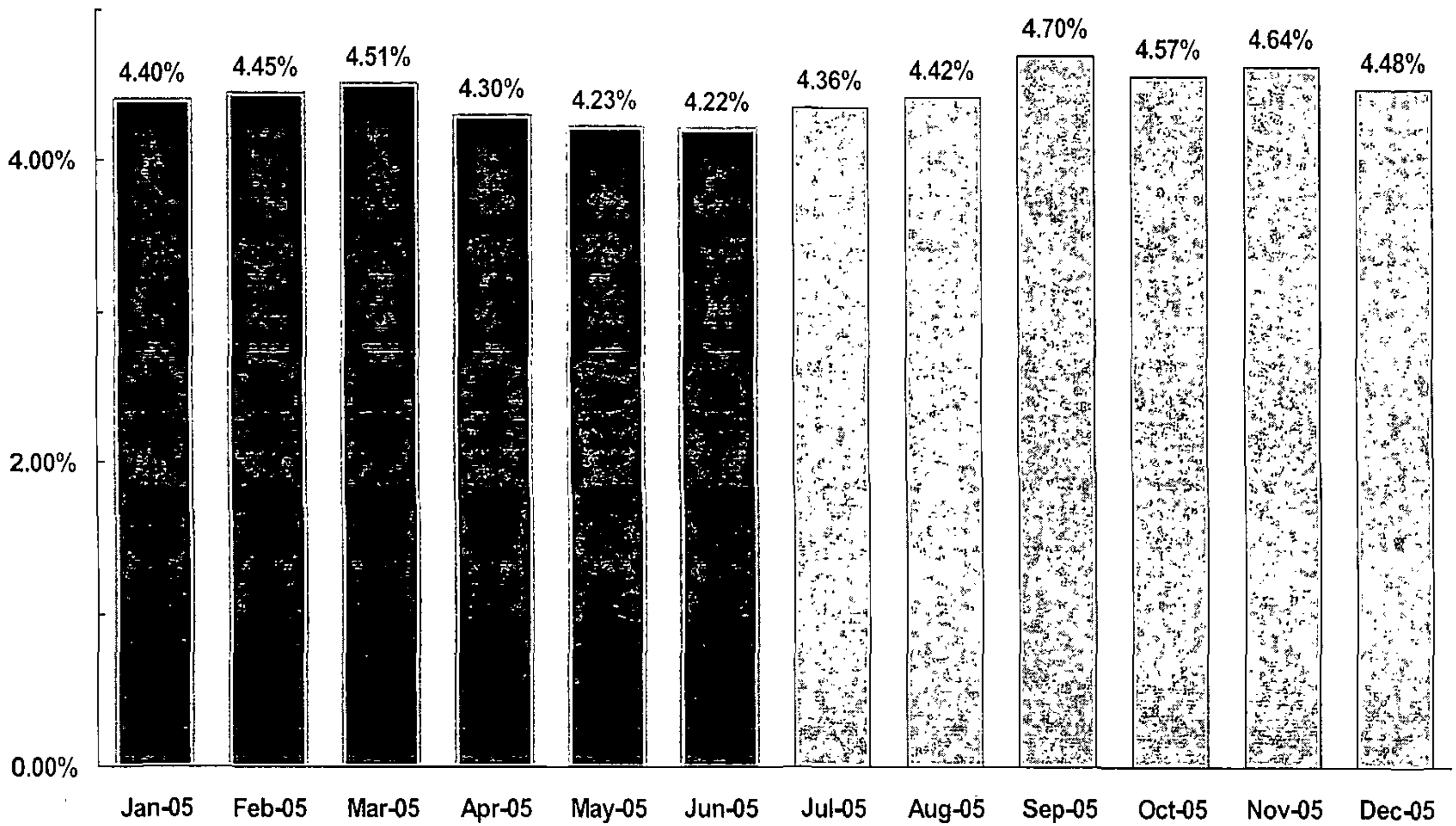
Series	Dividend Rate	Date of Issue	Principal Amount Outstanding	Discount and Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [1]
3.75% Series	3.75%	09/19/50	$ 7,500,000	$ 54,410	$ 7,445,590	99.27%	3.78%
4.00% Series	3.336% [2]	08/25/50	27,498,450	11,489	27,486,961	99.96%	3.34%
4.10% Series	4.10%	07/01/54	6,000,000	51,006	5,948,994	99.15%	4.14%
4.15% Series	4.15%	09/24/52	7,000,000	46,600	6,953,400	99.33%	4.18%
4.20% Series	4.20%	12/14/53	5,000,000	52,915	4,947,085	98.94%	4.24%
6.50% Series	6.50%	04/16/04	75,000,000	1,899,354	73,100,646	97.47%	6.67%
$2.10 Series	4.20%	01/25/55	8,000,000	57,998	7,942,002	99.28%	4.23%

Notes: [1] For series without sinking fund requirements, the effective cost rate is the nominal dividend rate divided by the net proceeds ratio.
[2] After tax cost

Source of Information: Company provided data

Electric Group

Monthly Dividend Yields



Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending January 2006

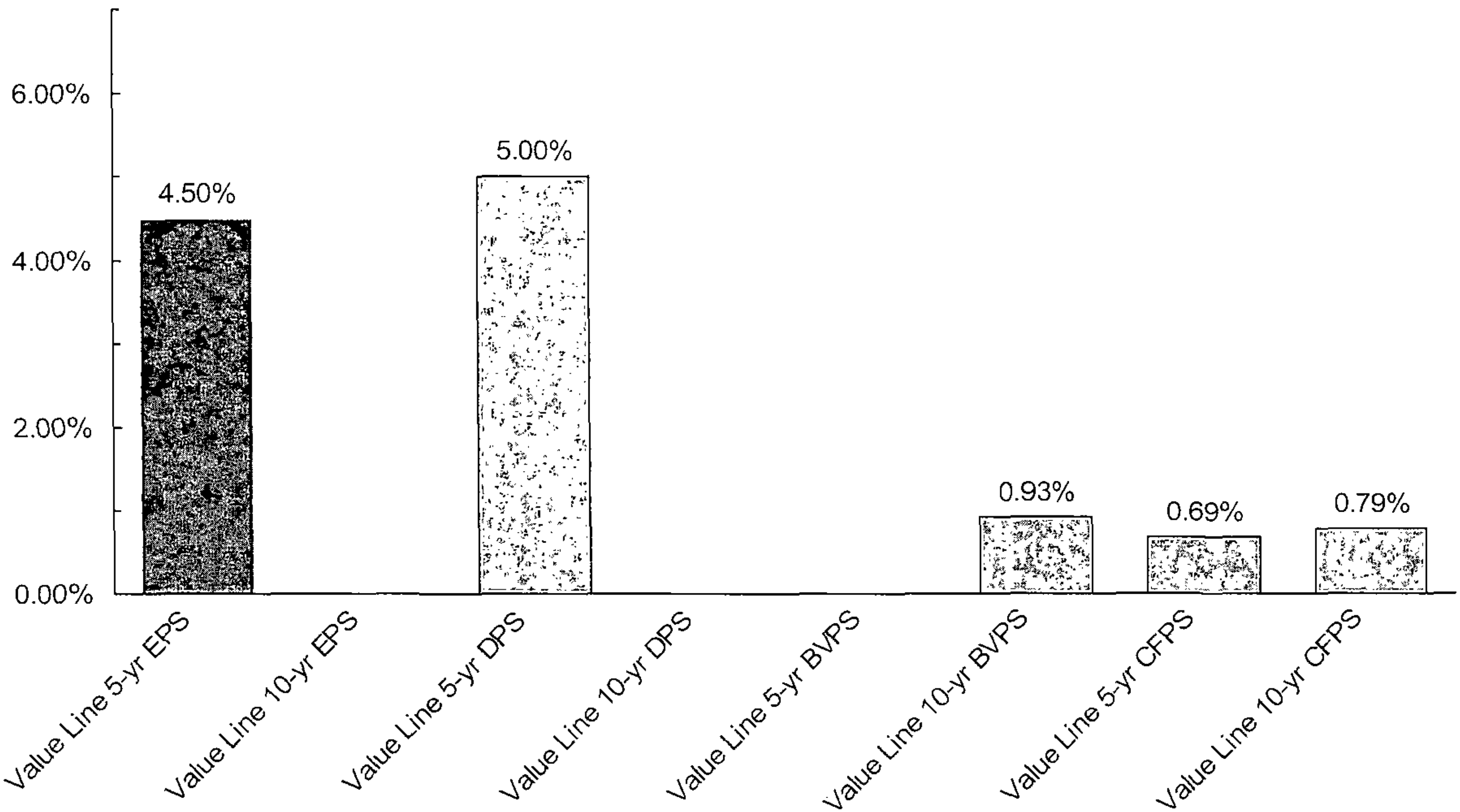
Company	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	12-Month Average	6-Month Average	3-Month Average
CH ENERGY GROUP INC (NYS	4.71%	4.78%	5.08%	4.81%	4.49%	4.41%	4.52%	4.60%	4.66%	4.66%	4.76%	4.62%			
CENTRAL VT PUB SVC CORP (	4.11%	4.12%	4.36%	4.40%	5.02%	4.95%	4.84%	5.31%	5.75%	4.53%	5.16%	4.76%			
CONSOLIDATED EDISON INC (	5.34%	5.44%	5.33%	5.02%	4.90%	4.78%	4.87%	4.72%	5.06%	5.02%	4.95%	4.94%			
DUQUESNE LT HLDGS INC (NY	5.40%	5.60%	5.73%	5.32%	5.37%	5.19%	5.58%	5.83%	6.05%	5.98%	6.15%	5.61%			
ENERGY EAST CORP (NYSE:E	4.30%	4.23%	4.24%	3.95%	3.83%	3.95%	4.22%	4.41%	4.87%	4.98%	5.14%	4.68%			
GREEN MOUNTAIN PWR CORF	3.47%	3.42%	3.37%	3.45%	3.36%	3.42%	3.32%	3.04%	3.07%	3.41%	3.48%	3.34%			
NORTHEAST UTILS (NYSE:NU)	3.48%	3.38%	3.57%	3.28%	3.13%	3.26%	3.51%	3.52%	3.87%	3.77%	3.57%	3.54%			
NSTAR (NYSE:NST)	4.21%	4.32%	4.30%	3.99%	3.80%	3.83%	3.95%	4.05%	4.28%	4.16%	4.08%	4.28%			
PEPCO HOLDINGS INC (NYSE:	4.58%	4.78%	4.65%	4.48%	4.19%	4.22%	4.42%	4.31%	4.69%	4.66%	4.48%	4.55%			
Average	4.40%	4.45%	4.51%	4.30%	4.23%	4.22%	4.36%	4.42%	4.70%	4.57%	4.64%	4.48%	4.44%	4.53%	4.56%

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: BusinessWeek online
http://ccbn.aol.com Event Calendar - Split/Dividend data provided by FT Interactive Data

Electric Group

Historical Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

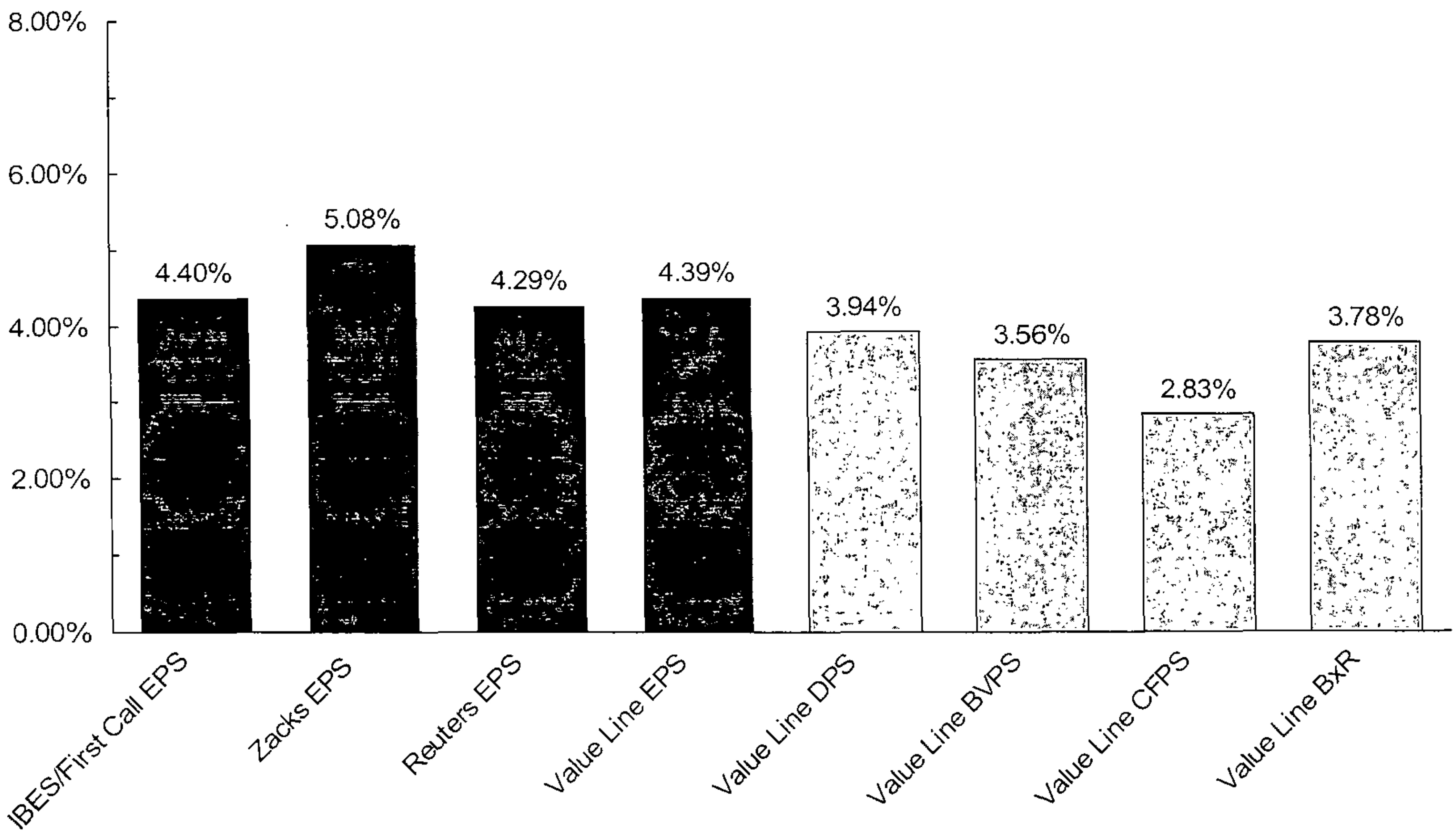
Exhibit PRM-1
Page 18 of 36
Schedule 9 [1 of 2]

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Electric Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
CH Energy Group	-3.00%	-0.50%	-	0.50%	2.00%	2.50%	-4.50%	-1.00%
Central Vermont P.S.	8.50%	-1.00%	0.50%	-4.50%	2.00%	2.00%	3.00%	-0.50%
Consolidated Edison	-2.00%	-	1.00%	1.50%	2.00%	2.50%	-1.50%	1.50%
Duquesne Light Holdings	-14.50%	-4.50%	-5.50%	0.50%	-17.50%	-7.50%	-13.00%	-4.00%
Energy East Corp.	-0.50%	3.00%	5.50%	-0.50%	5.50%	4.50%	4.50%	5.50%
Green Mountain Power	37.50%	-1.50%	-6.50%	-10.00%	-0.50%	-0.50%	7.50%	1.50%
Northeast Utilities	-	-6.00%	37.50%	-10.50%	2.00%	-	7.00%	-
NSTAR	5.00%	4.50%	2.50%	2.50%	1.50%	3.00%	2.50%	2.50%
PEPCO Holdings	5.00%	-	-	-	-	-	-	-
Average	4.50%	-0.86%	5.00%	-2.56%	-0.38%	0.93%	0.69%	0.79%

Source of Information: Value Line Investment Survey, December 2, 2005

Electric Group
Five-Year Projected Growth Rates



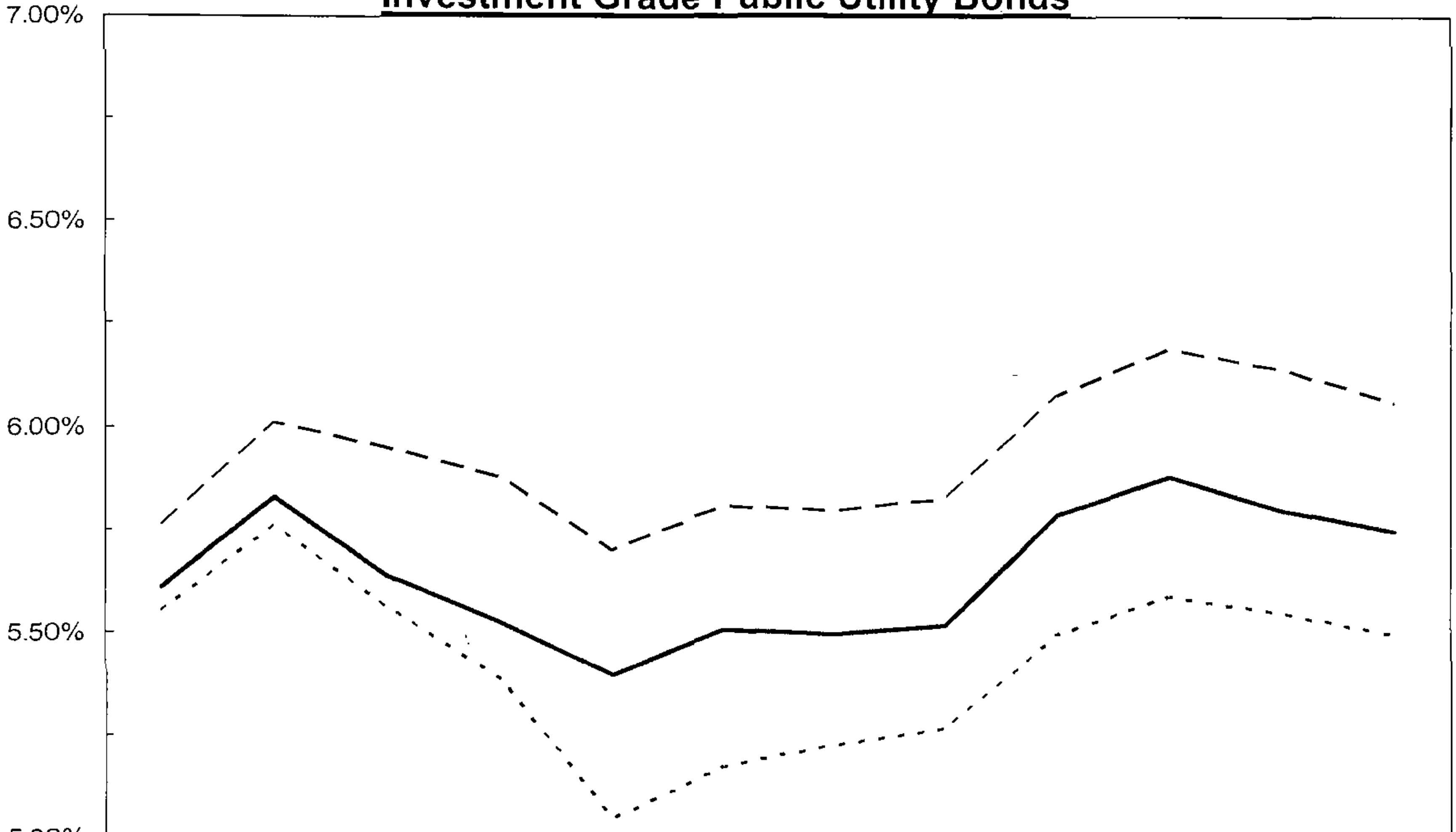
Earnings per Share=EPS   Book Values per Share=BVPS
Dividends per Share=DPS   Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Electric Group	I/B/E/S First Call	Zacks	Reuters Market Guide	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
CH Energy Group	-	N/A	-	4.50%	0.50%	2.00%	4.00%	3.00%
Central Vermont P.S.	-	N/A	-	2.50%	0.50%	NMF	0.50%	4.00%
Consolidated Edison	3.32%	4.00%	3.53%	1.50%	1.00%	2.50%	3.50%	2.00%
Duquesne Light Holdings	2.50%	5.00%	3.00%	3.00%	-1.50%	7.50%	-1.50%	3.50%
Energy East Corp.	4.50%	4.50%	4.33%	4.50%	5.00%	3.00%	2.50%	3.50%
Green Mountain Power	-	N/A	-	3.50%	12.00%	3.00%	1.50%	4.00%
Northeast Utilities	7.70%	8.70%	6.80%	11.00%	9.00%	2.50%	5.00%	5.00%
NSTAR	4.75%	4.80%	4.67%	2.50%	3.00%	5.50%	5.50%	4.00%
PEPCO Holdings	3.60%	3.50%	3.40%	6.50%	6.00%	2.50%	4.50%	5.00%
Average	4.40%	5.08%	4.29%	4.39%	3.94%	3.56%	2.83%	3.78%

Source of Information : Thomson Financial, January 20, 2006
Zacks, January 19, 2006
Market Guide, January 19, 2006
Value Line Investment Survey, December 2, 2005

Interest Rates for Investment Grade Public Utility Bonds



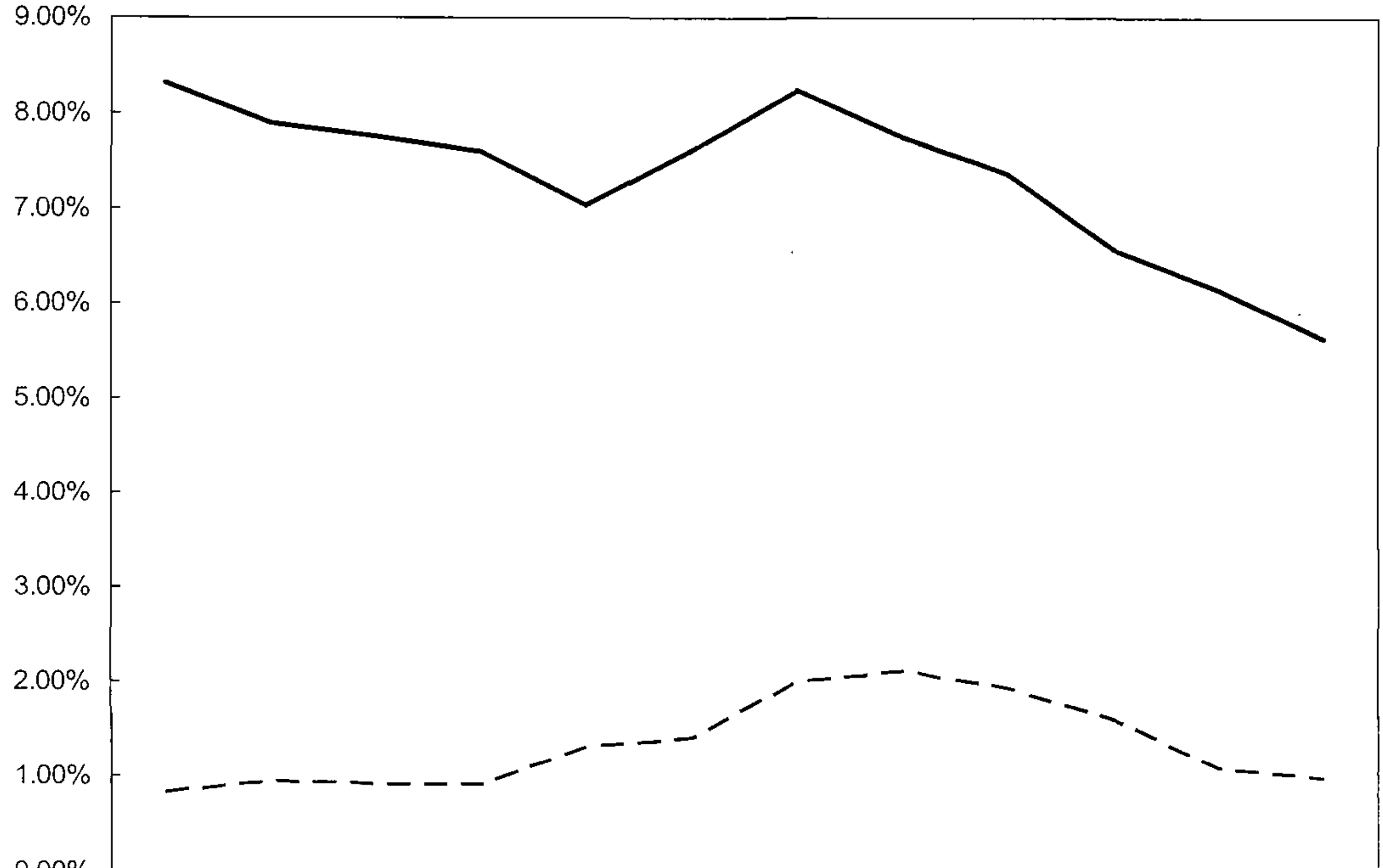
	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06
Aa	5.55%	5.76%	5.56%	5.39%	5.05%	5.18%	5.23%	5.27%	5.50%	5.59%	5.55%	5.50%
A	5.61%	5.83%	5.64%	5.53%	5.40%	5.51%	5.50%	5.52%	5.79%	5.88%	5.80%	5.75%
Baa	5.76%	6.01%	5.95%	5.88%	5.70%	5.81%	5.80%	5.83%	6.08%	6.19%	6.14%	6.06%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2000-2004 and 2005
and the Twelve Months Ended January 2006

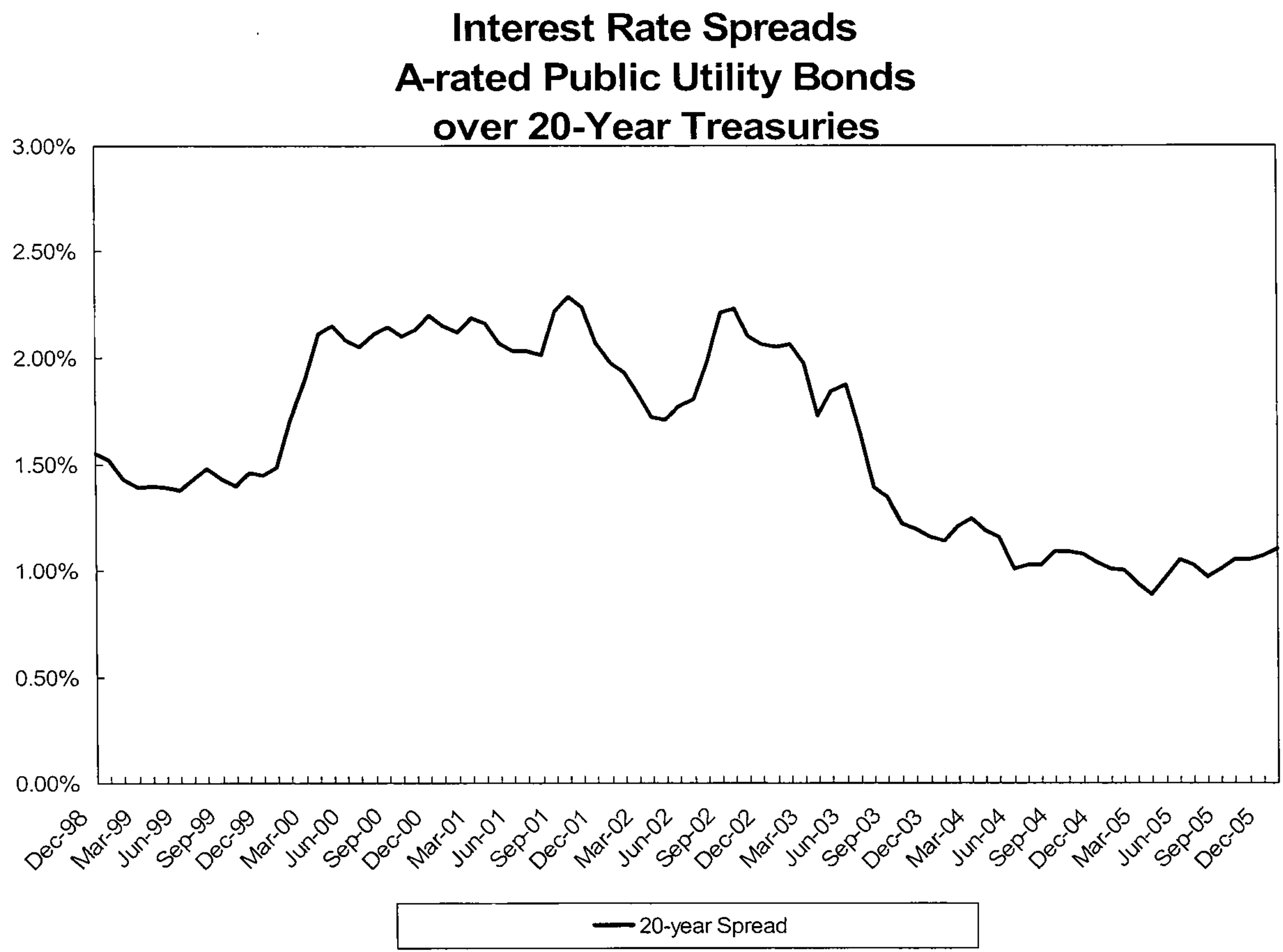
Years	Aa Rated	A Rated	Baa Rated	Average
2000	8.06%	8.24%	8.36%	8.14%
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
Five-Year Average	7.05%	7.22%	7.53%	7.24%
2005	5.44%	5.65%	5.93%	5.67%
Months				
Feb-05	5.55%	5.61%	5.76%	5.64%
Mar-05	5.76%	5.83%	6.01%	5.86%
Apr-05	5.56%	5.64%	5.95%	5.72%
May-05	5.39%	5.53%	5.88%	5.60%
Jun-05	5.05%	5.40%	5.70%	5.39%
Jul-05	5.18%	5.51%	5.81%	5.50%
Aug-05	5.23%	5.50%	5.80%	5.51%
Sep-05	5.27%	5.52%	5.83%	5.54%
Oct-05	5.50%	5.79%	6.08%	5.79%
Nov-05	5.59%	5.88%	6.19%	5.88%
Dec-05	5.55%	5.80%	6.14%	5.83%
Jan-06	5.50%	5.75%	6.06%	5.77%
Twelve-Month Average	5.43%	5.65%	5.93%	5.67%
Six-Month Average	5.44%	5.71%	6.02%	5.72%
Three-Month Average	5.55%	5.81%	6.13%	5.83%

Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.11%	1.00%


Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
Dec-98
Mar-99
Jun-99
Sep-99
Dec-99
Mar-00
Jun-00
Sep-00
Dec-00
Mar-01
Jun-01
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
20-year Spread

A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2005

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005 preliminary	4.91%	16.79%	5.87%	3.02%
Geometric Mean	10.03%	8.65%	5.89%	5.47%
Arithmetic Mean	11.99%	11.02%	6.21%	5.75%
Standard Deviation	20.26%	22.67%	8.61%	7.93%
Median	13.38%	11.50%	4.44%	4.55%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2005, 1952-2005, 1974-2005, and 1979-2005

Total Returns	Range: *Geometric* Mean	Range: Median	Midpoint	Point Estimate: *Arithmetic* Mean	Average of the Midpoint of Range *and Point* Estimate
1928-2005					
S&P Public Utility Index	8.65%	11.50%		11.02%	
Public Utility Bonds	5.47%	4.55%		5.75%	
Risk Differential	3.18%	6.95%	5.07%	5.27%	5.17%
1952-2005					
S&P Public Utility Index	10.82%	12.97%		12.37%	
Public Utility Bonds	6.21%	5.08%		6.52%	
Risk Differential	4.61%	7.89%	6.25%	5.85%	6.05%
1974-2005					
S&P Public Utility Index	12.54%	14.95%		14.57%	
Public Utility Bonds	8.70%	9.05%		9.06%	
Risk Differential	3.84%	5.90%	4.87%	5.51%	5.19%
1979-2005					
S&P Public Utility Index	13.15%	15.08%		15.06%	
Public Utility Bonds	9.15%	9.44%		9.49%	
Risk Differential	4.00%	5.64%	4.82%	5.57%	5.20%

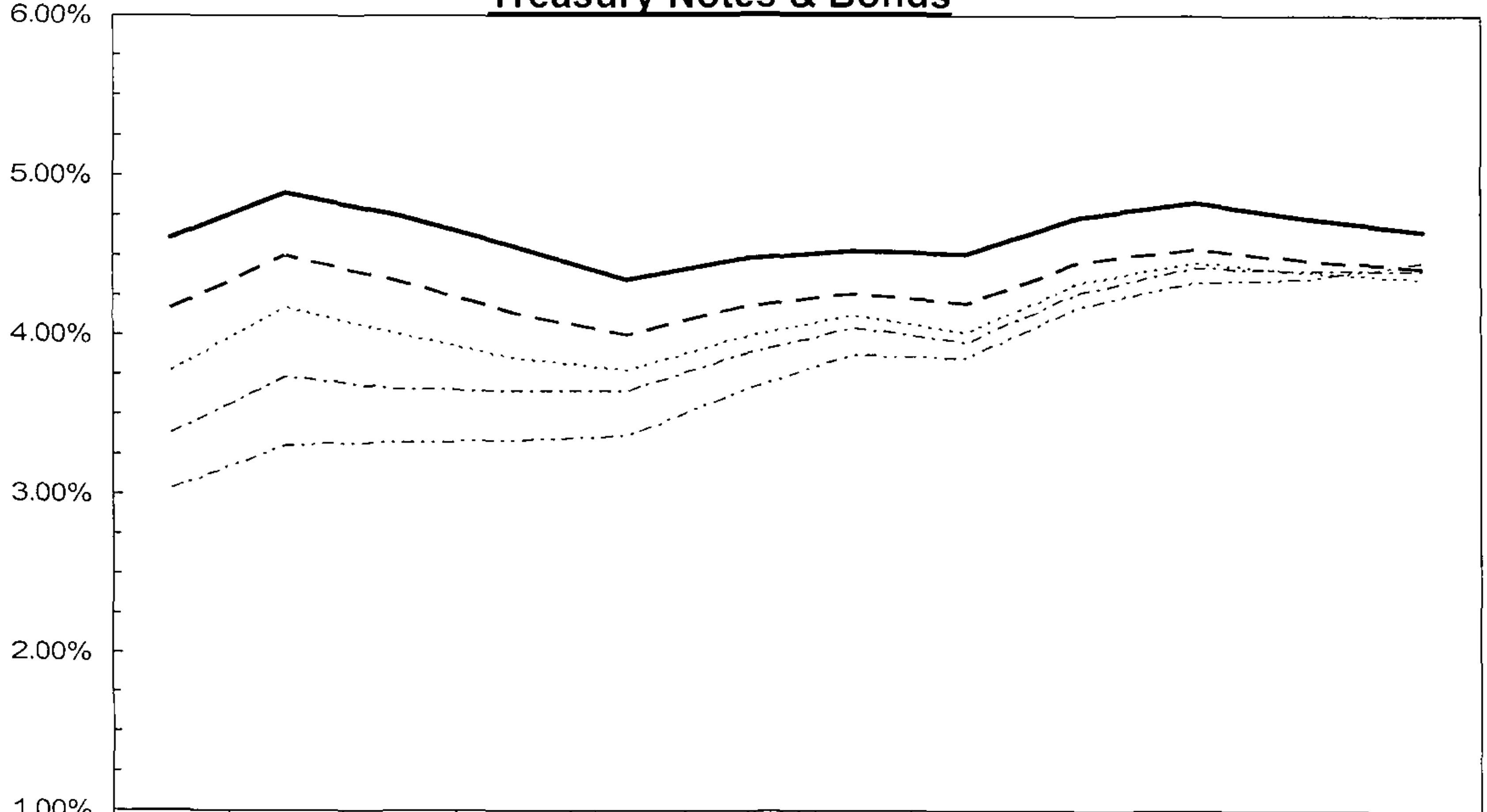
Value Line Betas

Electric Group

CH Energy Group	0.80
Central Vermont P.S.	0.55
Consolidated Edison	0.60
Duquesne Light Holdings	0.80
Energy East Corp.	0.85
Green Mountain Power	0.60
Northeast Utilities	0.80
NSTAR	0.75
PEPCO Holdings	0.90
Average	0.74

Source of Information:
Value Line Investment Survey
December 2, 2005

Yields on Treasury Notes & Bonds



	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06
1-Year	3.03%	3.30%	3.32%	3.33%	3.36%	3.64%	3.87%	3.85%	4.18%	4.33%	4.35%	4.45%
2-Year	3.38%	3.73%	3.65%	3.64%	3.64%	3.87%	4.04%	3.95%	4.27%	4.42%	4.40%	4.40%
5-Year	3.77%	4.17%	4.00%	3.85%	3.77%	3.98%	4.12%	4.01%	4.33%	4.45%	4.39%	4.35%
10-Year	4.17%	4.50%	4.34%	4.14%	4.00%	4.18%	4.26%	4.20%	4.46%	4.54%	4.47%	4.42%
20-Year	4.61%	4.89%	4.75%	4.56%	4.35%	4.48%	4.53%	4.51%	4.74%	4.83%	4.73%	4.65%

Yields for Treasury Constant Maturities
Yearly for 2000-2004 and 2005
and the Twelve Months Ended January 2006

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2000	6.11%	6.26%	6.22%	6.16%	6.20%	6.03%	6.23%
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.11%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.05%
Five-Year Average	2.95%	3.35%	3.66%	4.19%	4.55%	4.79%	5.46%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.65%
Months							
Feb-05	3.03%	3.38%	3.54%	3.77%	3.97%	4.17%	4.61%
Mar-05	3.30%	3.73%	3.91%	4.17%	4.33%	4.50%	4.89%
Apr-05	3.32%	3.65%	3.79%	4.00%	4.16%	4.34%	4.75%
May-05	3.33%	3.64%	3.72%	3.85%	3.94%	4.14%	4.56%
Jun-05	3.36%	3.64%	3.69%	3.77%	3.86%	4.00%	4.35%
Jul-05	3.64%	3.87%	3.91%	3.98%	4.06%	4.18%	4.48%
Aug-05	3.87%	4.04%	4.08%	4.12%	4.18%	4.26%	4.53%
Sep-05	3.85%	3.95%	3.96%	4.01%	4.08%	4.20%	4.51%
Oct-05	4.18%	4.27%	4.29%	4.33%	4.38%	4.46%	4.74%
Nov-05	4.33%	4.42%	4.43%	4.45%	4.48%	4.54%	4.83%
Dec-05	4.35%	4.40%	4.39%	4.39%	4.41%	4.47%	4.73%
Jan-06	4.45%	4.40%	4.35%	4.35%	4.37%	4.42%	4.65%
Twelve-Month Average	3.75%	3.95%	4.01%	4.10%	4.19%	4.31%	4.64%
Six-Month Average	4.17%	4.25%	4.25%	4.28%	4.32%	4.39%	4.67%
Three-Month Average	4.38%	4.41%	4.39%	4.40%	4.42%	4.48%	4.74%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated February 1, 2006

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	20-Year Treasury Bond
2006	First	4.6%	4.6%	4.6%	4.6%	4.8%
2006	Second	4.8%	4.8%	4.8%	4.8%	5.0%
2006	Third	4.8%	4.8%	4.8%	4.9%	5.1%
2006	Fourth	4.9%	4.9%	4.9%	4.9%	5.1%
2007	First	4.8%	4.9%	4.9%	4.9%	5.1%
2007	Second	4.7%	4.8%	4.9%	4.9%	5.1%

THE VALUE LINE Investment Survey®

Part 1 Summary & Index

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

January 13, 2006

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SCREENS

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

18.5

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
18.7	14.1	18.9

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

1.6%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
1.6%	2.4%	1.6%

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

40%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
50%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

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

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXI, No. 20.
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Table 7

Basic Series and Portfolios

Summary Statistics of
Annual Returns
From 1926 to 2005

Asset Class	1/1/26 to 12/31/05 Geometric Mean	Arithmetic Mean	Standard Deviation
Large Company Stocks	10.4%	12.3%	20.2%
Small Company Stocks	12.6%	17.4%	32.9%
Long-Term Corporate Bonds	5.9%	6.2%	8.5%
Long-Term Government Bonds	5.5%	5.8%	9.2%
Intermediate-Term Government Bonds	5.3%	5.5%	5.7%
U.S. Treasury Bills	3.7%	3.8%	3.1%
Inflation	3.0% E	3.1% E	4.3% E
90% Stocks/10% Bonds	10.1%	11.6%	18.3%
70% Stocks/30% Bonds	9.3%	10.3%	14.6%
50% Stocks/50% Bonds	8.4%	9.0%	11.5%
30% Stocks/70% Bonds	7.3%	7.7%	9.4%
10% Stocks/90% Bonds	6.1%	6.5%	8.8%

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 3, 4 & 5, Safety Rank of 1, 2, 3 & 4; Financial Strength of B, B+, B++, A, A+ & A++;
Price Stability of 70 to 100; Betas of .55 to .90; and Technical Rank of 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
3M Company	CHEMDIV	3	1	A++	90	0.90	3
Abbott Labs	MEDSUPPL	3	1	A++	80	0.85	4
ABM Industries Inc.	INDUSRV	3	2	B++	80	0.80	3
Alberto Culver	COSMETIC	3	1	A+	100	0.65	3
Alleghany Corp	INSPRPTY	4	1	A	100	0.60	3
Alliant Techsystems	DEFENSE	3	3	B+	70	0.75	3
Allied Capital Corp	FINANCL	3	2	B++	80	0.85	3
Allstate Corp	INSPRPTY	4	2	A	90	0.90	4
Altria Group	TOBACCO	3	3	B++	80	0.80	3
AmerisourceBergen	MEDSUPPL	3	3	B+	75	0.75	3
AmSouth Bancorp	BANK	3	2	B++	100	0.90	3
Anheuser-Busch	ALCO-BEV	5	1	A++	100	0.60	4
Applebee's Int'l	RESTRNT	4	3	B++	70	0.85	4
AptarGroup	PACKAGE	4	3	B+	90	0.90	3
Arbitron Inc.	INFOSER	3	3	B+	80	0.75	3
Archer Daniels Mid'd	FOODPROC	4	3	B+	85	0.70	3
Arrow Int'l	MEDSUPPL	5	2	A	90	0.60	4
Assoc. Banc-Corp	BANKMID	4	2	B++	95	0.90	3
AutoZone Inc.	RETAUTO	3	3	B	70	0.80	3
Avon Products	COSMETIC	5	2	B++	80	0.60	4
Ball Corp.	PACKAGE	4	3	B++	80	0.85	3
Banta Corp	PUBLISH	3	2	B++	95	0.75	3
Bard (C.R.)	MEDSUPPL	3	2	A	90	0.75	3
Barnes Group	DIVERSIF	3	3	B+	80	0.85	4
BB&T Corp.	BANK	3	1	A	100	0.90	3
Beckman Coulter	MEDSUPPL	5	3	B+	75	0.55	5
Becton Dickinson	MEDSUPPL	3	1	A+	90	0.80	3
Biomet	MEDSUPPL	3	2	A	75	0.80	3
Blyth Inc.	HOUSEPRD	5	2	B++	80	0.80	5
Bob Evans Farms	RESTRNT	4	2	B++	80	0.85	3
BOK Financial	BANKMID	3	2	B++	95	0.85	3
Brown-Forman 'B'	ALCO-BEV	3	1	A+	100	0.70	4
Campbell Soup	FOODPROC	3	2	B++	100	0.65	3
Capitol Fed. Fin'l	THRIFT	4	2	B++	95	0.70	3
Chevron Corp	OILINTEG	3	1	A++	100	0.85	4
Church & Dwight	HOUSEPRD	3	2	A	85	0.55	3
City National Corp	BANK	3	2	B++	95	0.80	3
CLARCOR Inc	PACKAGE	3	2	B++	85	0.90	3
Clorox Co	HOUSEPRD	4	2	B++	90	0.65	3
Coca-Cola	BEVERAGE	3	1	A++	95	0.65	3
Coca-Cola Bottling	BEVERAGE	3	3	B	80	0.55	3
ConAgra Foods	FOODPROC	4	2	B++	95	0.70	3
Constellation Brands	ALCO-BEV	3	3	B	70	0.75	4
Corn Products Int'l	FOODPROC	5	3	B+	85	0.75	3
Costco Wholesale	RETAIL	3	3	A	70	0.90	3
Deluxe Corp.	PUBLISH	5	3	B	90	0.75	4
Dentsply Int'l	MEDSUPPL	3	2	B++	90	0.70	3
Downey Fin'l	THRIFT	3	3	B++	70	0.90	4
Dun & Bradstreet	INFOSER	3	3	B	90	0.80	3
Edwards Lifesciences	MEDSUPPL	3	3	B++	80	0.70	4
Energizer Holdings	HOUSEPRD	4	3	B++	75	0.75	4
ESCO Technologies	DIVERSIF	5	3	B++	70	0.85	5
Exxon Mobil Corp	OILINTEG	3	1	A++	100	0.85	4
First Horizon National	BANKMID	4	3	B++	90	0.85	3
First Midwest Bancorp	BANKMID	4	2	B++	100	0.85	3
Freddie Mac	FINANCL	4	2	A	90	0.85	3
Gallagher (Arthur J.)	FINANCL	3	2	A+	75	0.90	3
Gannett Co	NWSPAPER	5	1	A++	95	0.85	3
Gen'l Dynamics	DEFENSE	3	1	A++	85	0.80	3
Gen'l Mills	FOODPROC	4	1	A	100	0.55	4
Graco Inc	MACHINE	3	2	B++	85	0.90	3
Harland (John H.)	PUBLISH	3	3	B++	75	0.70	3
Harte-Hanks	ADVERT	3	1	A	95	0.85	4
HCA Inc.	MEDSERV	3	2	A	75	0.60	4
Health Mgmt. Assoc.	MEDSERV	3	3	B+	70	0.70	4
Heinz (H.J.)	FOODPROC	3	1	A+	100	0.60	3
Hershey Co.	FOODPROC	3	1	A++	95	0.65	5
Hillenbrand Inds.	DIVERSIF	4	2	A	90	0.75	3
HNI Corp	FURNITUR	3	2	A	90	0.80	4
Hormel Foods	FOODPROC	3	1	A	95	0.70	3
Huntington Bancshs	BANKMID	3	3	B++	95	0.90	3
IHOP Corp	RESTRNT	3	3	B	75	0.90	4
Int'l Flavors & Frag.	CHEMSPEC	4	2	B++	95	0.75	3
Int'l Speedway 'A'	RECREATE	3	3	B+	85	0.75	3
Interactive Data	INFOSER	3	3	B++	70	0.90	3
Invacare Corp	MEDSUPPL	5	3	B+	80	0.80	5
Johnson & Johnson	MEDSUPPL	3	1	A++	100	0.70	4
Kellogg	FOODPROC	4	2	B++	100	0.60	3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Kellwood Co	APPAREL	4	3	B++	75	0.90	3
Kimball Int'l 'B'	FURNITUR	4	3	B++	75	0.80	3
Kimberly-Clark	HOUSEPRD	4	1	A++	100	0.65	3
Kraft Foods	FOODPROC	3	1	A+	100	0.65	4
Lancaster Colony	HOUSEPRD	4	1	A+	90	0.80	3
Lauder (Estee)	COSMETIC	4	2	A	80	0.85	3
Lee Enterprises	NWSPAPER	4	2	B++	100	0.65	3
Lilly (Eli)	DRUG	3	1	A++	85	0.80	4
Liz Claiborne	APPAREL	5	1	A+	85	0.90	3
Lockheed Martin	DEFENSE	3	2	A	85	0.70	4
MacDermid Inc.	CHEMSPEC	3	3	B+	75	0.85	3
Markel Corp	INSPRPTY	4	2	B++	95	0.80	4
Mattel Inc	RECREATE	3	3	B++	80	0.70	4
Matthews Int'l	DIVERSIF	3	3	B+	80	0.75	3
McClatchy Co	NWSPAPER	4	1	A	100	0.75	3
McGraw-Hill	PUBLISH	3	1	A+	95	0.80	3
Media General 'A'	NWSPAPER	5	3	B+	90	0.90	3
Meredith Corp.	PUBLISH	3	1	A	100	0.85	3
National Presto Ind	APPLIANC	3	2	B+	95	0.65	3
New York Times	NWSPAPER	4	1	A	90	0.90	3
Newell Rubbermaid	HOUSEPRD	3	3	B+	75	0.90	3
NIKE Inc. 'B'	SHOE	3	2	A+	75	0.90	3
Northrop Grumman	DEFENSE	3	2	B++	90	0.65	3
Outback Steakhouse	RESTRNT	4	3	B++	80	0.90	3
Owens & Minor	MEDSUPPL	3	3	B+	75	0.80	4
Packaging Corp	PACKAGE	4	3	B+	90	0.85	3
Pactiv Corp	PACKAGE	4	3	B+	80	0.85	3
Papa John's Int'l	RESTRNT	3	2	B++	80	0.75	3
Patterson Cos.	MEDSUPPL	4	2	A	75	0.65	4
People's Bank	THRIFT	3	3	B+	85	0.80	3
Pepsi Bottling Group	BEVERAGE	3	3	B	70	0.70	3
PepsiAmericas Inc.	BEVERAGE	3	3	B	90	0.80	3
Pfizer Inc	DRUG	3	1	A++	85	0.85	5
Pitney Bowes	OFFICE	4	2	A	95	0.90	3
Procter & Gamble	HOUSEPRD	4	1	A++	100	0.60	3
Protective Life	INSLIFE	4	2	B++	95	0.90	3
Regis Corp	COSMETIC	4	3	B+	75	0.90	3
Reinsurance Group	INSLIFE	3	3	B++	80	0.90	3
Republic Services	ENVIRONM	3	3	B+	85	0.70	3
RLI Corp	INSPRPTY	3	2	B++	90	0.75	3
Rollins Inc.	INDUSRV	3	3	B++	70	0.80	3
Ruddick Corp	GROCERY	5	3	B+	80	0.85	3
Ryan's Restaurant	RESTRNT	5	3	B	70	0.85	4
SAFECO Corp.	INSPRPTY	3	3	B+	80	0.85	3
Scripps (E.W.) 'A'	NWSPAPER	4	2	B+	100	0.85	3
Sensient Techn	FOODPROC	4	3	B+	80	0.80	4
ServiceMaster Co	INDUSRV	3	3	B+	85	0.80	3
Smithfield Foods	FOODPROC	4	3	B	70	0.80	4
Smucker (J.M.)	FOODPROC	3	2	B++	85	0.70	4
Sonic Corp	RESTRNT	3	3	B+	75	0.75	5
St. Joe Corp	HOMEBILD	3	1	A	95	0.85	4
Standex Int'l	DIVERSIF	4	2	B++	80	0.90	3
Stryker Corp	MEDSUPPL	3	2	A	85	0.75	3
Sysco Corp	FOODWHOL	3	1	A++	90	0.75	3
Topps Co	RECREATE	4	3	B+	75	0.80	3
Toro Co	APPLIANC	3	2	B++	80	0.85	4
Transatlantic Hldgs	INSPRPTY	4	2	B++	95	0.80	3
Triarc Cos. 'A'	RESTRNT	3	3	B	100	0.70	3
Union Pacific	RAILROAD	3	3	B++	95	0.85	3
Universal Corp	TOBACCO	5	2	B++	95	0.70	4
UST Inc	TOBACCO	5	3	B+	85	0.90	4
V.F. Corp	APPAREL	4	2	A	85	0.90	4
Valspar Corp	CHEMSPEC	3	3	B+	90	0.90	3
Wal-Mart Stores	RETAIL	3	1	A++	90	0.85	3
Walgreen Co	DRUGSTOR	3	1	A++	85	0.75	3
Washington Federal	THRIFT	4	1	A+	95	0.85	3
Washington Group Int'l	BUILDING	3	3	B+	75	0.85	4
Washington Post	NWSPAPER	5	1	A+	100	0.70	3
Waste Connections	ENVIRONM	3	3	B+	70	0.85	5
Waste Management	ENVIRONM	3	3	B++	80	0.90	3
WD-40 Co	HOUSEPRD	4	3	B++	70	0.75	3
Webster Fin'l	BANK	5	3	B+	95	0.90	3
Weis Markets	GROCERY	3	1	A	95	0.75	3
Wells Fargo	BANK	3	1	A+	100	0.85	3
Wendy's Int'l	RESTRNT	4	2	A	80	0.70	3
West Pharmac. Svcs.	MEDSUPPL	4	3	B+	75	0.75	4
Wiley (John) & Sons	PUBLISH	4	3	B+	85	0.80	3
Wrigley (Wm.) Jr.	FOODPROC	4	1	A++	100	0.55	3
Zimmer Holdings	MEDSUPPL	3	2	A	75	0.75	3
Comparable Group	Average	4	2	B++	86	0.78	3
Electric Group	Average	4	2	B++	94	0.79	3

Source of Information: Value Line Investment Survey for Windows, January 13, 2006

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2000-2004 and
Projected 3-5 Year Returns

Company	2000	2001	2002	2003	2004	Average	Projected 2008-10
3M Company	28.4%	23.5%	32.9%	30.5%	28.8%	28.8%	25.5%
Abbott Labs.	32.5%	32.5%	30.4%	26.6%	24.6%	29.3%	23.5%
ABM Industries Inc.	13.7%	12.5%	12.1%	8.2%	9.5%	11.2%	14.0%
Alberto Culver	15.3%	15.0%	16.0%	15.3%	14.9%	15.3%	13.5%
Alleghany Corp.	2.9%	15.8%	4.0%	10.4%	3.5%	7.3%	7.0%
Alliant Techsystems	34.2%	15.5%	27.0%	28.8%	22.4%	25.6%	15.0%
Allied Capital Corp	13.8%	14.8%	14.7%	10.0%	12.6%	13.2%	15.0%
Allstate Corp.	12.1%	6.9%	11.9%	12.9%	14.2%	11.6%	15.5%
Altria Group	56.7%	43.6%	48.3%	36.7%	30.7%	43.2%	25.5%
AmerisourceBergen	35.1%	4.9%	10.8%	11.2%	10.8%	14.6%	9.5%
AmSouth Bancorp.	20.0%	18.1%	19.5%	19.4%	18.9%	19.2%	19.0%
Anheuser-Busch	37.6%	42.0%	63.4%	76.6%	84.0%	60.7%	42.0%
Applebee's Int'l	22.4%	21.1%	21.1%	21.6%	22.3%	21.7%	18.5%
AptarGroup	14.7%	13.8%	11.8%	10.2%	10.7%	12.2%	11.5%
Arbitron Inc	-	-	-	-	124.2%		33.0%
Archer Daniels Mid'd	4.9%	6.1%	6.8%	6.2%	9.7%	6.7%	9.5%
Arrow Int'l	17.0%	14.3%	13.1%	13.3%	12.5%	14.0%	11.0%
Assoc. Banc-Corp	17.3%	16.8%	16.6%	17.0%	12.8%	16.1%	15.5%
AutoZone Inc	27.0%	31.3%	62.1%	NMF	NMF	40.1%	NMF
Avon Products	-	-	-	179.0%	89.0%		36.0%
Ball Corp	16.6%	21.0%	32.3%	29.4%	27.7%	25.4%	20.0%
Banta Corp	15.8%	14.2%	13.3%	11.7%	12.6%	13.5%	14.0%
Bard (C.R.)	20.4%	18.2%	20.1%	19.5%	19.3%	19.5%	21.5%
Barnes Group	17.7%	9.6%	13.0%	10.3%	10.8%	12.3%	13.5%
BB&T Corp.	18.3%	17.0%	17.9%	10.7%	14.3%	15.6%	18.0%
Beckman Coulter	36.5%	27.3%	26.9%	20.3%	18.3%	26.1%	14.5%
Becton Dickinson	20.1%	18.8%	19.3%	19.6%	22.0%	20.0%	20.5%
Biomet	18.4%	17.2%	20.4%	22.3%	22.5%	20.2%	24.5%
Blyth Inc.	23.0%	16.5%	16.9%	17.0%	19.0%	18.5%	12.5%
Bob Evans Farms	11.1%	12.5%	13.4%	11.4%	5.7%	10.8%	10.5%
BOK Financial	14.2%	15.2%	13.8%	12.9%	12.8%	13.8%	13.0%
Brown-Forman 'B'	19.6%	17.4%	29.2%	24.5%	22.9%	22.7%	28.0%
Campbell Soup	NMF	NMF	NMF	NMF	74.7%	74.7%	27.0%
Capitol Fed. Fin'l	7.7%	7.4%	9.1%	5.3%	4.8%	6.9%	9.0%
Chevron Corp	26.0%	9.7%	3.6%	19.9%	29.5%	17.7%	17.5%
Church & Dwight	20.9%	19.1%	19.4%	17.9%	15.9%	18.6%	13.0%
City National Corp	17.7%	16.4%	16.3%	15.3%	15.3%	16.2%	17.0%
CLARCOR Inc	16.6%	15.3%	14.8%	14.7%	14.9%	15.3%	13.0%
Clorox Co	23.4%	20.2%	23.8%	42.3%	35.5%	29.0%	61.0%
Coca-Cola	39.4%	35.0%	34.7%	34.0%	31.5%	34.9%	32.0%
Coca-Cola Bottling	9.5%	38.5%	69.0%	58.5%	33.9%	41.9%	32.0%
ConAgra Foods	27.0%	17.1%	18.2%	18.2%	16.4%	19.4%	17.0%
Constellation Brands	15.8%	14.4%	16.4%	11.2%	11.3%	13.8%	12.0%
Corn Products Int'l	6.4%	6.7%	7.6%	8.3%	8.7%	7.5%	10.5%
Costco Wholesale	14.9%	12.3%	12.3%	11.0%	11.6%	12.4%	11.5%
Deluxe Corp	64.5%	236.5%	333.2%	NMF	NMF		NMF
Dentsply Int'l	19.4%	18.0%	17.5%	15.4%	13.6%	16.8%	14.0%
Downey Fin'l	15.9%	16.4%	13.6%	11.1%	10.7%	13.5%	16.0%
Dun & Bradstreet	-	-	-	NMF	NMF		35.0%
Edwards Lifesciences	NMF	13.7%	15.4%	15.2%	16.6%	15.2%	16.5%
Energizer Holdings	26.3%	13.2%	26.4%	21.0%	45.5%	26.5%	22.5%
ESCO Technologies	5.4%	6.1%	7.1%	12.0%	12.6%	8.6%	14.0%
Exxon Mobil Corp	23.9%	20.6%	14.8%	18.9%	24.9%	20.6%	20.5%
First Horizon National	16.8%	20.7%	22.3%	25.0%	22.3%	21.4%	16.5%
First Midwest Bancorp	16.9%	18.4%	18.3%	17.8%	18.6%	18.0%	18.5%
Freddie Mac	24.7%	15.0%	32.2%	15.3%	9.0%	19.2%	15.0%
Gallagher (Arthur J.)	27.9%	33.7%	26.5%	26.7%	24.8%	27.9%	20.5%
Gannett Co	19.0%	14.5%	16.8%	14.4%	16.1%	16.2%	14.5%
Gen'l Dynamics	23.6%	20.8%	20.2%	16.8%	16.8%	19.6%	15.0%
Gen'l Mills	NMF	NMF	16.2%	24.0%	20.8%	20.3%	21.5%
Graco Inc	63.2%	37.6%	30.8%	NMF	47.1%	44.7%	39.0%
Harland (John H.)	16.7%	19.3%	22.4%	22.0%	20.1%	20.1%	17.5%
Harte-Hanks	14.9%	14.4%	17.0%	15.7%	17.1%	15.8%	17.5%
HCA Inc	20.5%	21.9%	21.9%	21.5%	28.3%	22.8%	23.0%
Health Mgmt. Assoc.	16.3%	15.6%	18.3%	17.3%	16.4%	16.8%	16.5%
Heinz (H.J.)	65.8%	49.3%	59.5%	41.1%	31.8%	49.5%	22.0%
Hershey Co	28.1%	32.9%	31.8%	37.1%	48.6%	35.7%	42.0%
Hillenbrand Inds.	18.7%	17.7%	19.8%	21.1%	17.5%	19.0%	15.5%
HNI Corp	18.5%	15.2%	14.1%	13.6%	17.0%	15.7%	18.0%
Hormel Foods	19.5%	18.3%	17.0%	14.8%	15.6%	17.0%	15.5%
Huntington Bancshs	13.9%	12.1%	14.8%	17.0%	15.7%	14.7%	14.0%
IHOP Corp.	13.6%	12.9%	11.2%	11.1%	12.0%	12.2%	16.0%
Int'l Flavors & Frag.	23.7%	25.8%	32.0%	26.9%	21.5%	26.0%	16.0%
Int'l Speedway 'A'	5.7%	8.5%	17.1%	15.0%	15.0%	12.3%	12.0%
Interactive Data	NMF	0.7%	9.2%	9.5%	9.4%	7.2%	9.5%
Invacare Corp	15.1%	15.8%	13.5%	11.6%	10.0%	13.2%	11.5%
Johnson & Johnson	25.5%	24.3%	30.0%	30.1%	29.2%	27.8%	24.5%
Kellogg	72.6%	61.1%	79.4%	54.5%	39.5%	61.4%	27.0%

Company	2000	2001	2002	2003	2004	Average	Projected 2008-10
Kellwood Co	14.1%	7.8%	9.2%	11.3%	9.7%	10.4%	9.0%
Kimball Int'l 'B'	10.3%	8.2%	5.8%	1.3%	5.0%	6.1%	9.5%
Kimberly-Clark	31.2%	30.9%	30.9%	25.4%	27.2%	29.1%	33.0%
Kraft Foods	14.2%	8.0%	13.6%	12.1%	10.7%	11.7%	10.5%
Lancaster Colony	24.6%	19.6%	16.6%	16.1%	13.4%	18.1%	15.0%
Lauder (Estee)	20.7%	20.3%	15.8%	18.7%	21.7%	19.4%	26.5%
Lee Enterprises	14.9%	9.7%	9.6%	9.7%	9.8%	10.7%	10.5%
Lilly (Eli)	48.0%	42.4%	32.7%	28.6%	28.1%	36.0%	29.0%
Liz Claiborne	23.1%	19.1%	18.5%	17.7%	17.3%	19.1%	13.0%
Lockheed Martin	6.0%	10.8%	18.0%	15.6%	18.0%	13.7%	20.5%
MacDermid Inc.	18.7%	9.1%	17.0%	20.3%	17.5%	16.5%	19.0%
Markel Corp	NMF	NMF	3.2%	6.1%	9.8%	6.4%	13.5%
Mattel Inc.	20.9%	20.5%	24.6%	24.9%	21.3%	22.4%	22.0%
Matthews Int'l	22.0%	21.0%	21.1%	17.5%	18.0%	19.9%	15.0%
McClatchy Co	9.3%	6.3%	12.5%	11.9%	11.1%	10.2%	10.5%
McGraw-Hill	26.2%	25.9%	26.6%	24.6%	24.7%	25.6%	21.5%
Media General 'A'	4.6%	1.5%	5.0%	4.9%	6.8%	4.6%	7.5%
Meredith Corp	21.3%	17.8%	11.2%	18.4%	18.8%	17.5%	20.5%
National Presto Ind.	6.2%	2.7%	3.6%	6.3%	6.0%	5.0%	7.0%
New York Times	28.1%	22.2%	24.1%	21.5%	20.9%	23.4%	15.5%
Newell Rubbermaid	18.5%	13.1%	20.5%	20.2%	21.6%	18.8%	22.5%
NIKE Inc. 'B'	18.5%	16.9%	17.4%	18.5%	19.8%	18.2%	16.5%
Northrop Grumman	15.9%	5.5%	4.8%	4.8%	6.4%	7.5%	11.0%
Outback Steakhouse	17.5%	15.0%	15.6%	16.9%	14.5%	15.9%	17.0%
Owens & Minor	15.6%	15.8%	18.1%	13.1%	13.1%	15.1%	13.5%
Packaging Corp	18.9%	14.0%	6.1%	5.3%	6.3%	10.3%	18.0%
Pactiv Corp	9.3%	9.8%	24.5%	21.7%	20.4%	17.1%	15.0%
Papa John's Int'l	28.5%	24.2%	38.4%	23.0%	28.1%	28.4%	16.5%
Patterson Cos	18.7%	18.5%	18.4%	18.6%	18.1%	18.5%	15.0%
People's Bank	12.3%	2.6%	5.9%	6.4%	7.8%	7.0%	12.5%
Pepsi Bottling Group	13.9%	17.5%	23.5%	22.4%	23.4%	20.1%	15.5%
PepsiAmericas Inc.	5.8%	6.3%	9.4%	9.8%	10.8%	8.4%	11.0%
Pfizer Inc	40.4%	45.6%	47.9%	19.5%	23.6%	35.4%	21.0%
Pitney Bowes	48.8%	62.4%	67.0%	52.3%	46.0%	55.3%	32.0%
Procter & Gamble	34.4%	36.6%	36.9%	35.4%	37.5%	36.2%	25.5%
Protective Life	12.3%	10.1%	10.0%	9.8%	10.8%	10.6%	11.5%
Regis Corp	18.8%	15.6%	15.8%	15.4%	15.3%	16.2%	15.0%
Reinsurance Group	12.3%	4.0%	10.5%	8.5%	9.9%	9.0%	11.0%
Republic Services	13.4%	12.1%	12.6%	11.3%	12.7%	12.4%	17.0%
RLI Corp	8.8%	9.0%	8.4%	10.6%	10.3%	9.4%	11.0%
Rollins Inc.	17.2%	19.8%	29.9%	25.8%	26.1%	22.8%	18.0%
Ruddick Corp	10.8%	10.8%	12.3%	12.1%	11.8%	11.6%	12.5%
Ryan's Restaurant	14.9%	14.2%	15.7%	14.0%	12.1%	14.2%	8.5%
SAFECO Corp	2.1%	NMF	6.1%	8.1%	14.5%	7.7%	12.0%
Scripps (E.W.) 'A'	12.8%	10.6%	15.2%	13.6%	13.8%	13.2%	13.5%
Sensient Techn.	16.7%	15.1%	16.2%	13.4%	11.5%	14.6%	11.0%
ServiceMaster Co	15.9%	9.4%	14.0%	19.4%	17.4%	15.2%	19.0%
Smithfield Foods	14.7%	14.4%	2.0%	10.1%	15.7%	11.4%	9.5%
Smucker (J.M.)	13.4%	12.2%	9.3%	10.0%	8.9%	10.8%	11.0%
Sonic Corp	21.0%	19.4%	20.7%	19.7%	18.8%	19.9%	15.0%
St. Joe Corp	16.7%	10.9%	31.5%	15.6%	17.2%	18.4%	17.5%
Standex Int'l	18.5%	14.5%	11.4%	11.1%	13.5%	13.8%	16.0%
Stryker Corp	25.9%	25.7%	23.8%	21.0%	21.3%	23.5%	27.0%
Sysco Corp	25.8%	27.8%	31.9%	35.4%	35.4%	31.3%	30.0%
Topps Co	45.0%	14.7%	8.6%	6.0%	5.9%	16.0%	9.5%
Toro Co	14.3%	14.8%	17.4%	18.5%	26.0%	18.2%	27.0%
Transatlantic Hldgs.	11.4%	1.0%	8.3%	12.8%	9.8%	8.7%	11.5%
Triarc Cos. 'A'	NMF	2.7%	NMF	NMF	0.5%	1.6%	20.0%
Union Pacific	9.0%	8.7%	9.3%	8.5%	6.0%	8.3%	10.0%
Universal Corp.	23.7%	21.4%	18.1%	18.3%	13.5%	19.0%	13.0%
UST Inc.	163.3%	84.6%	-	NMF	NMF		48.0%
V.F. Corp	15.4%	14.3%	22.4%	20.1%	18.7%	18.2%	16.0%
Valspar Corp	19.8%	7.9%	16.3%	12.9%	14.3%	14.2%	14.0%
Wal-Mart Stores	20.1%	19.1%	20.4%	20.3%	20.8%	20.1%	21.5%
Walgreen Co	17.9%	16.7%	16.3%	16.1%	16.5%	16.7%	18.0%
Washington Federal	13.9%	13.0%	15.0%	13.8%	11.8%	13.5%	14.5%
Washington Group Int'l	-	-	6.3%	6.4%	7.0%	6.6%	8.5%
Washington Post	9.1%	4.3%	11.4%	8.7%	13.7%	9.4%	12.5%
Waste Connections	8.9%	10.3%	12.8%	12.2%	10.9%	11.0%	15.5%
Waste Management	15.6%	13.6%	15.2%	13.2%	13.7%	14.3%	16.5%
WD-40 Co	38.9%	30.6%	30.5%	27.9%	22.8%	30.1%	18.5%
Webster Fin'l	28.9%	28.5%	36.6%	40.8%	11.8%	29.1%	11.0%
Weis Markets	7.9%	10.1%	10.4%	9.5%	10.0%	9.6%	10.0%
Wells Fargo	15.2%	12.6%	18.8%	18.0%	18.5%	16.6%	17.5%
Wendy's Int'l	16.1%	18.8%	15.1%	13.4%	14.2%	15.5%	12.5%
West Pharmac. Svcs	8.3%	11.8%	6.4%	10.6%	13.6%	10.1%	14.5%
Wiley (John) & Sons	26.8%	23.5%	22.3%	20.7%	23.0%	23.3%	14.0%
Wrigley (Wm.) Jr.	29.0%	28.4%	26.4%	24.5%	22.6%	26.2%	22.5%
Zimmer Holdings	73.6%	242.4%	70.4%	9.3%	15.2%	82.2%	13.5%
Average						19.4%	17.7%
Median						16.7%	15.5%