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PP&L

Direct Testimony

Volume 1

Statements 1-8

Docket No. R-00973954

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Pennsylvania Power & Light Company
Docket No. R-00973954
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 1

Direct Testimony of Joseph P. Kalt, Ph.D.

I INTRODUCTION: OVERVIEW AND WITNESS QUALIFICATIONS

I.A Qualifications

Q. Please state your name and business address.

A. I am Joseph P. Kalt. My business address is The Economics Resource Group, Inc., One Mifflin Place, Cambridge, MA 02138.

Q. What is your professional and educational background?

A. I am the Ford Foundation Professor of International Political Economy and the Chairman of the Economics and Quantitative Methods Section at the John F. Kennedy School of Government, Harvard University. I have also been the Academic Dean for Research, Faculty Chair of the Kennedy School's Environment and Natural Resources Program, Chairman of Degree Programs, and Chairman of Ph.D. Programs. I specialize in natural resources and energy policy, and have published widely on matters relating to the regulation of natural gas, electricity, oil, and coal markets. I have testified in numerous administrative, judicial, and Congressional proceedings concerning the performance of the nation's energy markets.

I received the Master's (1977) and Ph.D. (1980) degrees in economics from the University of California, Los Angeles, and an undergraduate degree in economics from Stanford University (1973). I joined the faculty at Harvard in 1978, and served as Instructor, Assistant Professor, and Associate Professor in the Department of Economics before becoming a Professor in the Kennedy School of Government in 1986. During my years at Harvard I have had responsibility for the teaching of graduate courses in antitrust and regulation, microeconomics, and environment and natural resource policy, among others. I have received research grants from the National Science Foundation, the Ford Foundation, the Northwest Area Foundation, the IRIS Fund, and many other sources. A detailed description of my qualifications, research publications, and related background is provided in Exhibit JPK-1.

I.B Overview of Testimony

Q. Please describe the purpose of your testimony.

A. I have been asked by Pennsylvania Power & Light Company (the "Company" or "PP&L") to articulate the conditions necessary to restructure the electric power industry consistent with sound economic principles and public policy objectives and to evaluate whether or not the Company's filing is consistent with these principles. The transition to a restructured electricity industry offers the potential for improvement in the efficiency of the industry and the value that it delivers to customers. To realize this potential, however, restructuring proposals need to have four key ingredients: proper treatment of stranded costs, efficient rate design, even-handed rules for competition and open access, and appropriate ratepayer protection. I address each of these key ingredients in turn after reviewing the economic and public policy principles that should be applied to electric industry restructuring.

II ECONOMIC AND PUBLIC POLICY PRINCIPLES IN ELECTRICITY RESTRUCTURING

II.A The Setting

Q. Professor Kalt, please describe the economic and regulatory setting that currently exists with regards to restructuring the electric power industry.

A. Over the last several decades, a wave of deregulation and increased competition has swept regulated industries, including telecommunications, natural gas, railroads, banking, airlines, stock brokerage and trucking; privatization and decreased regulation have also spread through many industries, including electric utilities, in Great Britain, New Zealand, Australia and elsewhere. This trend is consistent with what economic principles and practical experience confirm: competition is a powerful force in promoting the public's interest in a healthy, efficient economy. In some industries, however, economies of scale[1] and/or economies of scope[2] can create conditions of what economists call "natural monopoly." In industries characterized by natural monopoly, a single firm or a small number of firms can produce the entire industry output at lower cost than if that same output were divided up among many firms. Unless an affected market is rendered "contestable" by the ability of firms to enter and exit freely as the prospect of above-competitive pricing waxes and wanes, robust competition is not feasible in industries characterized by natural monopoly. In the U.S. at least, the classic response to problems of natural monopoly in private markets has been to regulate firms in such markets as public utilities.

In the past, the U.S. electric power industry, in virtually all its stages from generation through transmission and down to retail distribution, has been subjected to pervasive regulation under traditional public utility principles. In fact, this regulatory model was little objected to for decades as real electricity costs declined steadily and electricity consumption consistently grew faster than the economy as a whole. Beginning in the 1970s, however, this relatively placid

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[1] Economies of scale are said to exist when costs rise less than proportionately with the level of total production.

[2] Economies of scope are said to exist when it is less costly to produce multiple products, or serve multiple customers, with a single firm than it is to produce those products or serve those customers with multiple firms.

picture began to unravel. Rapidly accelerating inflation, combined with volatile fuel prices and shortages of natural gas, created tremendous pressure on electric rates and pushed utilities to abandon construction of natural gas and oil-fired base-load generation in favor of coal and nuclear plants. In fulfillment of franchise obligations to ensure sufficient capacity, and aware of the long lead times necessary for the construction of nuclear plants, the regulatory process in many jurisdictions operated to induce and require many utilities to initiate and carry through large construction programs to create the additional capacity that was anticipated to be needed in the 1980s and 1990s.

In many cases, however, events and circumstances (including restrained growth, availability of substitutes, need for reliable service to meet high peak load combined with the capital-intensive nature of the industry, and energy conservation) have combined to leave utilities with excess capacity. This excess capacity has resulted in a situation in which the price of electricity that would occur in unregulated competitive markets would be below the embedded, average cost of producing that power. Herein lies the policy problem: Excess capacity in the electric power industry implies pressure toward (and concomitant political support for) lower prices, but traditional principles of public utility regulation have operated to insulate franchise utilities from competitive pressures. Removal of that protection would effectively deny them the opportunity to recover costs prudently incurred in the course of fulfilling their obligations as publicly-regulated utilities.

In response to high costs, technological changes, successes in deregulating other industries, low natural gas fuel prices, and international competitive pressures, Federal legislation and regulatory policy are moving the electricity industry towards a new structure. The basic outlines of this structure are now clear: The generation sector of the industry is not generally naturally monopolistic and is being opened to competition. Transmission and distribution sectors, however, exhibit strong economies of single-firm operation and will likely continue to be regulated. In order for power generators to compete to sell electricity, Federal policy now requires transmission owners to provide access to their transmission systems on the same terms and conditions (including access to information) as those owners provide to their own vertically-integrated generation and distribution operations.

It is in this context that the Pennsylvania legislature enacted the Electricity Generation Customer Choice and Competition Act (the "Act") to bring to Pennsylvania the benefits of competition while addressing the proper regulatory approach for the remaining natural monopoly elements of the electricity industry. During the resulting transition to a new industry structure and policy, there are many important issues and competing interests that regulators must contend with to move successfully ahead. Customers want lower prices and protection from changing prices, utilities want to recover their investments, and all citizens have a stake in a healthy and efficient electricity industry. Given the heightened importance of properly transitioning to and arriving at an improved industry and regulatory structure, the present proceeding is not just another rate case in Pennsylvania. *Instead, this proceeding is a critical step in applying sound* economic and public policy principles to restructuring the electricity industry.

II.B Summary of Pennsylvania's Legislation

Q. Professor Kalt, what are the key public policy goals of the Act?

A. The Act states: "The transition to a competitive generation market shall be orderly, protect electric system reliability, be fair to ratepayers and provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the commission determines to be just and reasonable."[3]

Q. What specific policies does the Act adopt in order to achieve its objectives?

A. The Act contains a variety of policies that are designed to work hand in glove to achieve its objectives. The Act provides for recovery of utilities' transition or stranded, non-mitigable costs within nine years subject to a rate cap. It

[3] Section 2804(14) of the Act.

also provides that there should be no inter- or intra-class cost shifting and requires the use of a non-bypassable and competitively neutral access charge as a stranded cost recovery mechanism. Consumers will have unbundled rates so that they can choose their energy supplier directly. Customer choice begins with a pilot program and then is phased in over several years. Consumer programs and services, such as universal service and energy conservation measures, will continue.

Q. Can you summarize the important findings of the Act?

A. The Act finds in part that: (1) competitive market forces are more effective than economic regulation in controlling the cost of generating electricity; (2) the Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect the Commonwealth's ability to compete in the national and international marketplace; (3) in moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, nonutility generators of electricity and other affected parties;

and (4) electric service should be available to all customers on reasonable terms and conditions.[4]

II.C Sound Economic and Public Policy Principles that Apply to Electricity Restructuring

Q. Professor Kalt, please describe the economic and public policy principles that should be applied to electricity restructuring.

A. The findings and policies of the Pennsylvania Legislature provide a sound framework for restructuring. A restructured electricity industry offers the potential for improvement in the efficiency of the industry and the value that it delivers to customers. To realize this potential, however, restructuring will have to be implemented so as to foster efficient competition within a framework defined by a set of key policy principles that are consistent with the Act. These principles lie in four primary areas of policy concern:

Stranded Investment

- Provide the opportunity for utilities to recover the above-market portion of cost obligations that have been incurred in fulfillment of responsibilities stemming from *ex ante* pre-reform public utility policy and law.

[4] Sections 2802(5) and (7-9) of the Act.

Rate Design

- Create a non-bypassable access charge for retail consumers in order to provide a mechanism for recovery of the costs of over-market generation and regulatory assets while ensuring no distortion to competitive market access;
- Move towards more efficient, market-driven pricing of electricity, and encourage development of a wider variety of products and services than currently exists;

Competition and Access Rules

- Rely on market forces to establish the price, mix and performance characteristics of power production and capacity;
- Make transmission and distribution services available on an unbundled basis and under comparable rates, terms and conditions to both utility-affiliated and independent suppliers and marketers of electric power and related services;
- Use appropriate self-dealing rules to govern the relationships between transmission/distribution entities and affiliated companies that compete for electricity sales;

Ratepayer Benefits and Protection

- Provide for ratepayer access to benefits from supplier-expanding competition and related regulatory reform;
- Ensure ratepayer protection from the burden of rising rates for regulated services during the period of transition to competition and recovery of stranded costs;
- Maintain guarantees of consumer access to electric power service and related consumer protection;
- Maintain safe and reliable electric service for all consumers.

III TREATMENT OF STRANDED COSTS

Q. Professor Kalt, what is the major financial implication of changing the regulatory structure of the electric power industry?

A. The introduction of competition into the electric utility sector constitutes a fundamental change in public policy. It is now widely recognized that this change creates a problem of "stranded" costs—costs that were incurred by utilities playing by the then-existing rules of the game, but that cannot be recovered at market prices.

Despite semantic and legalistic arguments to the contrary, it has been recognized at the highest levels of economic and public policy-making that there exists a "regulatory compact" that has historically governed the relationship between regulated utilities and the government; and that this compact appropriately requires that regulatory reform not take away the reasonable prospect for recovery of costs that utilities incurred pursuant to their obligations under the regulatory regime in place at the time of their key cost-creating decisions.[5] In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve,

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[5] This principle has been recognized by, among others, the President's Council of Economic Advisers. Economic Report of the President, February 1996, Ch. 6.

utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in the just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to cost-of-service regulatory principles rather than market forces.

Of course, in a period of excess capacity and increased ability to "shop around" for power supplies, it is understandable that self-interested parties would desire to avoid paying for costs that have turned out to be above market prices. But it is disingenuous to assert that the pre-reform regulatory regime did not constitute a laying down of the rules of the game by the public sector. The rules of the game told private investors that the general rule and expectation was that costs *incurred* would be recoverable under cost-of-service principles; they did not tell investors "costs will be recoverable if competition allows them to be." Indeed, assertions that the public sector was not party to a regulatory compact upon which investors relied when they incurred costs is belied by the incontrovertible observation that the regulatory reform now underway in Pennsylvania and elsewhere represents a fundamental change in the rules of the game. In fact, the reforms underway are *fundamental* in precisely the way implied by the issue of stranded costs: We are moving to a regulatory regime in which substantial segments of the industry will no longer be subjected to cost-of-service regulation. Instead, recovery of costs incurred now and in the future will be subjected to the test of competitive viability. If the rules of the game were not being changed in this fundamental way, legislatures would not have to act and principled regulators would not have to preside over proceedings as extensive and far-reaching as these.

Q. But, couldn't it be argued that investors had no guarantee that the rules of the game wouldn't change, and they could anticipate fundamental change?

A. This kind of argument does not alter the conclusions that Pennsylvania's reforms represent fundamental change, and that failure to provide for recovery of stranded costs would constitute a breach of the reasonable expectations of utility shareholders and employees developed over decades of governmental involvement in their decisions. Government is the promulgator and enforcer of the rules of the game. If it uses its power to alter those rules after other parties have sunk investments into the game, such action imposes costs on all of the citizens under its jurisdiction. As underdeveloped and unstable countries around the world have taught us, instability in the rules of the game by which investors must play is the recipe for failure. In a world of intense international competition and capital that can flee from policy instability, regulatory change in Pennsylvania's electric power sector that would have the effect of stranding utilities' previously incurred costs would be decidedly contrary to the public's interest in a healthy Pennsylvania economy. One immediate consequence of policy instability would be a higher cost of capital for firms investing in Pennsylvania, particularly transmission and distribution utilities.

Q. Does the Act properly address and define stranded costs?

A. Yes. In addressing the competing interests referred to above and in *establishing a process for the transition to a competitive generation market*, the Act properly allows for the recovery of "transition or stranded costs." It defines these costs as "an electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility."[6] The Act acknowledges the long-term commitments that utilities were required

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[6] Section 2803 of the Act.

to undertake in order to fulfill their obligation to serve. The Act states: "...public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market."[7]

Q. Professor Kalt, are you aware that some argue that there was no regulatory compact?

A. Yes. These arguments are beside the point given the fact that the Pennsylvania Legislature recognizes stranded costs.

Q. Are all stranded costs recoverable under the Act?

A. No. The Act provides for a transition period during which stranded costs can be recovered. Any costs remaining after that time will not be recovered through regulated rates. In addition, the Act imposes several rate caps, which will limit the annual recovery of stranded costs. Moreover, if market prices drop below the level anticipated when stranded costs were originally

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[7] Section 2802(15) of the Act.

estimated, thereby increasing stranded costs, the Act prevents the raising of the competitive transition charge ("CTC") except under extreme circumstances, and it directs that consumers see the benefit of the actual, lower real prices. Alternatively, if market prices rise above the level that was used to estimate stranded costs and to set the CTC, the Company may charge no more than the generation-related rate cap. Thus, the recovery of stranded costs is constrained both in time and in amount. This puts shareholders at risk for otherwise recoverable investments that utilities made.

Q. What role should stranded cost mitigation play in stranded cost recovery?

A. Utilities should be required, as they are under the Act, to take appropriate measures to reduce their costs as they prepare for competition. As Mr. Hill describes, PP&L has taken many steps in the areas of refinancing, O&M cost reductions, employee reductions, inventory reductions, power plant operations, and economic development initiatives.

Q. How should stranded costs be calculated?

The first step in calculating stranded costs is to estimate the price of electricity that would occur in a competitive market. Price in a competitive market equilibrium equals the short-run marginal cost of the marginal producer. The next step is to determine the revenues the utility would receive based on the forecast of the market price of power. The net present value of the difference between these revenues and the utility's known and measurable net generation-related costs which traditionally would be recoverable under a regulated environment and which will remain after mitigation is the utility's stranded investment. PP&L employs this methodology in this filing.[8]

IV RATE DESIGN

Q. Will the recovery of stranded costs distort competition?

A. If done properly, recovery of stranded costs can be accomplished without distorting competition. In order to achieve a swift and orderly transition to a restructured industry, the sunk costs of generation assets made uneconomic by the transition, and the value of assets created by regulatory action, should

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[8] See the testimony of Dr. Jones and Mr. Schadt.

be recovered through a non-bypassable charge paid by all retail electricity customers, regardless of supplier. By recovering stranded costs from all users of the electricity system, this charge will permit restructuring to yield competition based on the merits of each competitor. Since this charge is paid by all parties using the transmission and distribution system, it permits stranded cost recovery without tilting the competitive balance for or against any party. The CTC as defined in the Act is a proper non-bypassable charge, and is an important component of PP&L's rate proposal.[9]

Q. Are there other economic and public policy guidelines applicable to rate design in a restructured electric power industry?

A. In the standard economic analysis of competition, consumers' ability to "shop around" to find the best price for a particular product ensures that goods and services will be produced efficiently. Producers enter a market based on their expectations of making a profit, and high-cost, inefficient producers cannot survive for long because they lose money at the prices charged by efficient producers. Efficient producers, meanwhile, tend to see their production levels and, hence, market shares rise. This process is at the heart of the economic argument as to why competition is generally efficient.

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[9] Section 2803 of the Act. Also see the testimony of Dr. Tierney.

The situation "on the ground" in the electricity industry is not this simple. *If* the prices charged by the existing utility suppliers of power approximated their incremental resource cost, then allowing other firms to compete for their customers would likely increase efficiency by the mechanism described in the previous paragraph. Utility customers would choose new suppliers only if those other suppliers offered a better deal. But the suppliers could profitably offer a better deal only if their *costs* were lower than the utilities' *prices*. Thus, *if* utilities' prices reflect their incremental costs, consumers choosing the lower-*priced* alternative would also be choosing the alternative that was lowest-*cost* in terms of society's resources.[10]

Utility prices in Pennsylvania (and elsewhere) do not, however, necessarily or even typically approximate their true going-forward economic costs. There are a number of reasons for this situation: (1) Pennsylvania utilities have incurred certain costs in pursuit of their obligation to serve and under regulatory oversight which can only be recovered by charging prices that exceed going-forward costs of supplying power; (2) many Pennsylvania utilities are required to engage in public-policy activities such as mandatory universal service programs that the competitive market would not necessarily

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[10] Broadman, H. and J. Kalt, "How Natural is Natural Monopoly? The Case of Bypass in Natural Gas Distribution Markets," Yale Journal of Regulation, Summer 1989.

support; and (3) electricity rates for many consumers in Pennsylvania are not now structured to show marginal cost price signals.

In this situation, competition will be inefficient and *increase* overall costs unless rate structures are carefully designed. An efficient rate structure will have two key features: (1) a universal access charge that is paid by all customers, regardless of their supplier, and that is designed to recover sunk costs and the cost of regulatory and state-created obligations; and (2) a rate structure in which new suppliers must compete against utilities' going-forward "incremental" costs. I have already noted that the CTC satisfies the first of these criteria.

With respect to the second criterion, only by forcing new entrants to compete against utilities' incremental costs will regulators ensure that competition lowers costs rather than raises them. The relevant concept of cost for this purpose depends on market conditions. In the long run, prices should reflect the "all-in" cost of electric generation, including the cost of financing the capital investment. If, however, there is surplus generating capacity (as is currently the case in the mid-Atlantic region and elsewhere), then the true social cost of incremental electricity generation is currently only the short-run "incremental cost" of that generation. That is, the short-run incremental cost comprises the only resources that are used up, and hence not available for other productive use, by utility generation of electricity. If the utility does not generate electricity, society does not have the capital that is sunk in utility generation facilities available for some other use. Efficiency requires that new entrants be able to provide electricity at a price at or below this short-run incremental cost. Otherwise, the entry of new firms into generation will raise the overall social cost of delivering electricity to Pennsylvania customers. The Act's proposed unbundling of electric energy from transmission and distribution services will foster efficient competition between utility generation and other power suppliers.

Q. What are other important features of PP&L's rate design proposal?

A. PP&L's proposal contains several other rate design features. As required by the Act, the Company's rates are capped, which means customers will experience an energy and capacity rate reduction in real terms for approximately a decade (see further below). Moreover, once the transition period is completed, PP&L cannot recover any of its stranded costs that remain. In addition, residential customers will have the ability to choose an alternative supplier and will be able to switch back to PP&L within a grace period without any changes in their original rates. Finally, PP&L's proposed rates will result in significant reductions in the marginal cost of electricity for its customers. The Company's rate design reduces the kilowatt-hour charge for incremental energy purchased. This change has important efficiency implications. At the margin, customers under the new rate design will see prices that better reflect the social cost of generating electricity. This provides consumer benefits and permits them to make more efficient choices in their personal and business purchases. It also reduces the risk associated with the recovery of stranded costs.

V COMPETITION AND ACCESS RULES

Q. Professor Kalt, could you describe the steps that the Pennsylvania Legislature has taken to provide consumers with access to competitive energy suppliers and how these steps fit in with Federal policy?

A. Three necessary conditions for efficient competition among electricity providers are that competitors must compete at incremental costs, consumers must have the information necessary to make intelligent decisions regarding who their supplier should be, and energy suppliers should have access to transmission and distribution on comparable terms and conditions.

Q. Why is comparable access a necessary condition for effective competition?

A. There is a legitimate and important concern that exists regarding the interaction between the regulated and unregulated portions of a utility's business. The issue is: Can a utility leverage its transmission and distribution assets to exclude in whole or in part non-affiliate wholesale and retail generators and marketers?

In theory, there are two ways that control of transmission and distribution assets could translate into market abuse in electricity markets. First, if PP&L or its affiliates have superior access to these resources; or if customers purchasing electricity from the company have superior access to these delivery resources, then the company might be able to translate this superior access into higher prices for electricity that other competitors cannot discipline. Second, if the nature of regulation of prices for transmission and distribution services were to operate in such a way that the Company could use revenues from distribution and transmission to subsidize its competitive electricity sales operations, then the Company would have an advantage in these markets, and could charge prices lower than other competitors and perhaps prevent their entry.

To prevent these abuses, it is appropriate for the Commission, along with other regulators, to enforce functional separation of competitive electricity marketing activities from the distribution and transmission activities of the Company. If wholesale and retail electricity marketing are separated from transmission and distribution, then it is possible to enforce comparability of access to the transmission and distribution system. The wholesale and retail marketing arms of the Company properly should be required to deal with the transmission and distribution arms on the same bases that are available to competing marketing entities. This means that goods, services, or information that is provided by the regulated transmission/distribution operation to generation or marketing entities should be provided under the same rates, terms, conditions, and restrictions as are imposed on other parties.

The issue of possible cross-subsidy arises from the continued cost-of-service regulation of the distribution and transmission activities. Because the distribution/transmission arm is entitled to recovery of its costs through regulated distribution and transmission tariffs, a utility company that could "disguise" some of its electricity marketing costs as distribution or transmission costs could have the ability to impose those costs on transmission/distribution customers (i.e., non-affiliate energy suppliers) that compete with utility-affiliated unregulated activities, thereby giving affiliated activities a step up on their third-party competitors. To prevent this, costs of the transmission/distribution and marketing arms should be properly allocated, and operational "firewalls" should exist between regulated and unregulated activities. As I discuss below, PP&L has proposed precisely such measures.

Q. What measures is PP&L taking to ensure comparability of access to its transmission and distribution systems and to ensure against cross-subsidy?

A. First, the Company's implementation of a rate cap greatly mitigates any risk of cross-subsidy. This is because cross-subsidy can derive from the ability of the regulated entity to increase prices if its costs increase, allowing it to "hide" marketing costs in increased distribution or transmission rates. The rate cap detaches distribution and transmission rates from future changes in costs, providing no means to increase distribution/transmission revenues to cover losses from competitive activities. Rate caps are a mechanism for ensuring functional separation. Second, the Company will make all of its regulated activities available to qualified third parties on the same rates, terms, conditions, and restrictions as those activities are made available to any unregulated affiliate or activity of the Company. Third, the Company is implementing organizational changes and instituting rules of conduct so that firewalls are erected and comparability of access is assured.

Q. Professor Kalt, please describe the organizational structure and rules of conduct that PP&L is implementing.

A. Starting with the Pennsylvania direct access pilot program, the Company is organizing itself into two major business groups to segregate electric generating supplier activities from electric delivery activities. This functional separation will be governed by a code of conduct and accompanying structural changes.

This code of conduct has eight primary components. First, the Electric Delivery Group of PP&L will not share information that would give the Generation Supply Group a competitive advantage. Information of this type would include information regarding alternative supplier pricing and billing information. Second, restrictions will exist to segregate employees and limit their transfer between the two Groups. Third, accounting and cost allocation procedures will be implemented so that charges for services between groups are appropriately priced, and separate accounting books will be kept for each group.

Fourth, the Delivery Group will not preferentially treat customers of its affiliates over customers of competitive energy supplies, and it will provide all of its services to all customers -- affiliated and unaffiliated alike -- at the same prices and under the same terms and conditions. Fifth, the application of tariffs and responses to requests will be done in a non-discriminatory manner. Sixth, the Company will educate its employees as to these codes of conduct; and seventh, it will conduct audits and implement procedural checks and safeguards to enforce them. Finally, a dispute resolution process will be established to record and resolve complaints pertaining to PP&L's code of conduct and functional separation.

Q. Professor Kalt, have similar codes of conduct worked in other partially regulated industries?

A. Yes. The interstate natural gas pipeline industry is a good example. Strict codes of conduct between the competitive gas producing and marketing affiliates and their regulated pipeline affiliates have worked well to prevent abuses of the types that I have described above while allowing pipeline firms to organize themselves in the ways they find most effective in meeting their customers' needs. Meanwhile, unregulated services that utilize regulated pipeline services have flourished and are overwhelmingly being provided by unaffiliated third parties. Regulated pipelines have not been able to leverage these third parties out of the way of affiliates.

Q. Dr. Kalt, is there a role for regulators in monitoring and enforcing functional separation of the regulated and unregulated activities of utilities?

A. Yes. It is a proper function of regulators to monitor these relationships and dealings, and to take appropriate actions as necessary to enforce functional separation. By allowing utilities to compete in the unregulated energy service markets, on comparable terms as other competitors, regulators can further competition and efficiency by permitting eminently viable suppliers to provide valuable services to Pennsylvania consumers. Regulators, however, properly should take appropriate measures to ensure that open and equal access occurs so as to ensure that viable non-utility competitors have the opportunity to flourish as well.

Q. How does PP&L's rate design stack up to the Act's objective of having direct access?

As described above, in order to have meaningful competition, competitors must compete against the true incremental cost of producing electricity. PP&L's unbundling and functional separation will put PP&L's electricity generation into direct and efficient competition with other suppliers' power. On the buyers' side of energy service markets, consumers must have the information necessary to make comparisons between potential suppliers. To do this, consumers must have unbundled bills. They must know how much they are paying for energy and capacity, and how much they are paying for transmission and distribution. PP&L will provide this information in customers' bills, along with additional consumer information programs, so that consumers have the knowledge and information needed to choose their suppliers.

VI RATEPAYER BENEFITS AND PROTECTION

Q. *Professor Kalt, please describe the ratepayer benefits that are likely to occur under PP&L's plan.*

A. Ratepayers stand to benefit from the Act and PP&L's proposal in four major ways. First, in the near-term, consumers will see a rate reduction in real terms due to the rate cap. Under the cap, the Company will have the incentive to cut costs and operate efficiently, because if it does not, its profits will suffer. Moreover, with the effects of inflation, the rate cap translates into declining real prices for consumers. Second, the shifting of utility fixed costs into access charges will result in reductions in the marginal rates paid by customers. Their incremental costs of electricity will be substantially lower than they otherwise would be, allowing consumers to respond to more efficient price signals and to increase their consumption of electricity at the margin when doing so is beneficial. Third, PP&L is proposing to expand its low-income program, and other important customer programs and protections will continue. PP&L will continue to stand as customers' supplier of last resort. Finally, the overall balance of consumer and investor interests in the Competition Act will permit PP&L to preserve a reliable and safe electric power system.

We should not lose sight of the long-term goals and impact of Pennsylvania's reforms. As competition expands, it is customers who will benefit. By enabling unregulated suppliers to access PP&L's transmission and distribution system, customers will benefit from access to competitively priced electricity. By enabling customers to shop across competitive suppliers and marketers, customers will be able to choose how to best meet their needs, and competitors will try to outdo themselves in attracting customers.

VII SUMMARY AND CONCLUSIONS

Q. Professor Kalt, please summarize your testimony.

A. By providing for a principled and balanced transition, Pennsylvania has positioned itself to respond to the national and regional development of competitive electricity markets, while avoiding potentially lengthy and large transaction costs of protracted litigation and potential bankruptcies. The four key ingredients in achieving the benefits of competition must be kept in mind. Transition or stranded costs must be recovered in such a way as to not distort competition. Rates must be designed so as to promote economic efficiency while avoiding inter- and intra-class cost shifting. Competition must be implemented in an even-handed manner, and ratepayers should continue to have protection, particularly during the transition, from rising prices. In mixing these ingredients properly, the Pennsylvania Public Utility Commission will help shape the regulatory and industry structure so that consumers will have the benefits of lower prices, a smooth transition to a fully competitive electricity supplier market, and choice of their electricity supplier.

Q. Does this conclude your testimony?

A. Yes.

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PROFESSIONAL EXPERIENCE

John F. Kennedy School of Government, Harvard University, Cambridge, MA
Ford Foundation Professor in International Economy, 1992 - present
Professor of Political Economy, 1986 - 1992

> Areas of specialization include Industrial Organization, Economics of Antitrust and Regulation, Natural Resource Economics, Public Choice and Political Economy, Microeconomic Theory.

Co-Director, The Harvard Project on American Indian Economic Development, 1987 - present
Academic Dean for Research, 1992 - 1994
Chairman, Environment and Natural Resources Program, Center for Science and International Affairs, 1990 - 1994
Chairman of Degree Programs, 1990 - 1992
Assistant Director for Natural Resources, Energy and Environmental Policy Center, 1985 - 1990
Co-Director, Harvard Study on the Future of Natural Gas Policy (with Frank C. Schuller), Energy and Environmental Policy Center, John F. Kennedy School of Government, 1984-86

Department of Economics, Harvard University, Cambridge, MA
Associate Professor of Economics, 1983 - 1986
Assistant Professor of Economics, 1980 - 1983
Instructor in Economics, 1978 - 1980

> Taught Economics of Antitrust and Regulation, Intermediate Microeconomics, and Principles of Economics.

President's Council of Economic Advisers, Washington DC
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> Analyzed federal energy, environmental, transportation, and tax policies.

EDUCATION

University of California, Los Angeles
Ph.D. in Economics, 1980
Dissertation: "Federal Control of Petroleum Prices: A Case Study of the Theory of Regulation"

University of California, Los Angeles
M.A. in Economics, 1977
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"The Development of Private Property Markets in Wilderness Recreation: An Assessment of the Policy of Self-Determination by American Indians," Political Economy Research Center Conference, Big Sky, MT, December 4-7, 1985.

"Lessons from the U.S. Experience with Energy Price Regulation," International Association of Energy Economists Delegation to the People's Republic of China, Beijing and Shanghai, PRC, June 1985.

"The Impact of Domestic Regulation on the International Competitiveness of American Industry," Harvard/NEC Conference on International Competition, Ft. Lauderdale, FL, March 7-9, 1985.

"The Welfare and Competitive Effects of Natural Gas Pricing," American Economic Association Annual Meetings, December 1984.

"The Ideological Behavior of Legislators," Stanford University Conference on the Political Economy of Public Policy, March 1984.

"Principal-Agent Slack in the Theory of Bureaucratic Behavior," Columbia University Center for Law and Economic Studies, 1984.

"The Political Power of the Underground Coal Industry," FTC Conference on the Strategic Use of Regulation, March 1984.

"Decontrolling Natural Gas Prices: The Intertemporal Implications of Theory," International Association of Energy Economists Annual Meetings, Houston, TX, November 1981.

"The Role of Government and the Marketplace in the Production and Distribution of Energy," Brown University Symposium on Energy and Economics, March 1981.

"A Political Pressure Theory of Oil Pricing," Conference on New Strategies for Managing U.S. Oil Shortages, Yale University, November 1980.

"The Politics of Energy," Eastern Economic Association Annual Meetings, 1977.

WORKSHOPS PRESENTED

University of Indiana; University of Montana; Oglala Lakota College; University of New Mexico; Columbia University Law School; Department of Economics and John F. Kennedy School of Government, Harvard University; MIT; University of Chicago; Duke University; University of Rochester; Yale University; Virginia Polytechnic Institute; U.S. Federal Trade Commission; University of Texas; University of Arizona; Federal Reserve Bank of Dallas; U.S. Department of Justice; Rice University; Washington University; University of Michigan; University of Saskatchewan; Montana State University; UCLA; University of Maryland; National Bureau of Economic Research; University of Southern California

OTHER PROFESSIONAL ACTIVITIES

Chief Mediator *In the Matter of the White Mountain Apache Tribe v. United States Fish and Wildlife Service*, re: endangered species management authority, May-December, 1994

Steering Committee, National Park Service, 75th Anniversary Symposium, 1991-93

Board of Trustees, Foundation for American Communications, 1989 to present
Editorial Board, *Economic Inquiry*, 1988 to present

Advisory Committee, Oak Ridge National Laboratory, Energy Division, 1987 to 1989

Commissioner, President's Aviation Safety Commission, 1987-88

Principal Lecturer in the Program of Economics for Journalists, Foundation for American Communications, teaching economic principles to working journalists in the broadcast and print media, 1979 to present

Lecturer in the Economics Institute for Federal Administrative Law Judges, University of Miami School of Law, 1983 to 1991

Research Fellow, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, 1981 to 1987

Editorial Board, MIT Press Series on *Regulation of Economic Activity*, 1984 to 1992

Research Advisory Committee, American Enterprise Institute, 1979 to 1985

Editor, *Quarterly Journal of Economics*, 1979 to 1984

Referee for *American Economic Review, Bell Journal of Economics, Economic Inquiry, Journal of Political Economy, Review of Economics and Statistics, Science Magazine, Journal of Policy Analysis and Management, Social Choice and Welfare, Quarterly Journal of Economics*, MIT Press, North-Holland Press, Harvard University Press, *American Indian Culture and Research Journal*

TEACHING EXPERIENCE

Introduction to Environment and Natural Resource Policy (Graduate, Kennedy School of Government); Seminar in Positive Political Economy (Graduate, Kennedy School of Government); Intermediate Microeconomics (Graduate, Kennedy School of Government);Natural Resources and Public Lands Policy (Graduate, Kennedy School of Government); Economics of Regulation and Antitrust (Graduate); Economics of Regulation (Undergraduate); Introduction to Energy and Environmental Policy (Graduate, Kennedy School of Government);
Graduate Seminar in Industrial Organization and Regulation; Intermediate Microeconomics (Undergraduate); Principles of Economics (Undergraduate); Seminar in Energy and Environmental Policy (Graduate, Kennedy School of Government)

HONORS AND AWARDS

Allyn Young Prize for Excellence in the Teaching of the Principles of Economics, Harvard University, 1978-79
and 1979-80

Chancellor's Intern Fellowship in Economics, 9/73 to 7/78, one of two awarded in 1973, University of
California, Los Angeles

Smith-Richardson Dissertation Fellowship in Political Economy, Foundation for Research in Economics and

Education, 6/77 to 9/77, UCLA

Summer Research Fellowship, UCLA Foundation, 6/76 to 9/76

Dissertation Fellowship, Hoover Institution, Stanford University, 9/77 to 6/78

Four years of undergraduate academic scholarships, 1969-1973; graduated with University Distinction and
Departmental Honors, Stanford University

Research funding sources have included: The National Science Foundation; USAID (IRIS Foundation); Pew Charitable Trust; Christian A. Johnson Family Endeavor; The Ford Foundation; The Northwest Area Foundation; the U.S. Department of Energy; the Research Center for Managerial Economics and Public Policy, UCLA Graduate School of Management; the MIT Energy Laboratory; Harvard's Energy and Environmental Policy Center; the Political Economy Research Center; the Center for Economic Policy Research, Stanford University; the Federal Trade Commission; and Resources for the Future

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 2

Direct Testimony of Ronald E. Hill

Q. Please state your full name and business address.

A. Ronald E. Hill, Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") as Senior Vice President - Financial.

Q. What are your responsibilities as Senior Vice President - Financial?

A. I am the Chief Financial Officer of the Company. The functional activities under my supervision include the accounting, finance and treasury activities of the Company.

Q. What is your educational background?

A. I graduated in 1964 from Carnegie Mellon University with a Bachelor of Science degree in Industrial Management. I received a Masters Degree in Business Administration from Lehigh University in 1972 and also attended Muhlenberg College taking several accounting courses. Additionally, I have attended numerous seminars and special courses related to the accounting and finance areas and also attended the Edison Electric Institute (EEI) Executive Leadership Program.

Q. How long have you been employed by PP&L and in what capacities?

A. I joined PP&L in 1964 as a graduate trainee. Following a two-year leave for military service, I rejoined PP&L as a Systems Analyst and was named Accountant in 1968. From 1968 through 1978, I served in various accounting positions, working principally in the budgeting, financial planning and financial reporting areas. In 1979, I was appointed Manager - Financial Reporting with responsibility for all internal and external financial reporting activities. In 1987, I was appointed to the position of Vice President and Comptroller with responsibility for all accounting, financial reporting, tax and depreciation functions. On January 1, 1994, I was appointed Senior Vice President - Financial, which is the position I now hold.

Q. Are you or have you been active in any industry organizations?

A. I am a past member and chairman of the EEI's Application of Accounting Principles and Accounting Research Committees, and am currently a member of the Finance Committee of EEI. I also am a member of the Board of Directors of Nuclear Electric Insurance Ltd., a mutual insurance company providing property and damage insurance for operators of nuclear generating facilities.

Q. Do you belong to any professional organizations?

A. I am a member of the Financial Executives Institute and am also a member of the Institute of Management Accountants.

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

A. My testimony first describes the past and future mitigation efforts undertaken by PP&L which have reduced its stranded cost claim in this proceeding. I also address the importance of reasonable stranded cost recovery in this case on the future ability of PP&L to provide safe and reliable service to its customers.

MITIGATION

Q. Why is mitigation an issue in this proceeding?

A. Under the Electricity Generation Customer Choice and Competition Act ("Act"), the Pennsylvania Public Utility Commission (the "PUC" or "Commission") is authorized "to determine the level of transition or stranded cost for each electric utility and provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such cost in accordance with the standards established" by the Act. 66 Pa. C.S. § 2802(15). Transition or stranded costs are defined as "an electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive generation market and which the Commission determines will remain following mitigation by the electric utility." 66 Pa. C.S. § 2803. In determining the appropriate amount of stranded cost recovery, the PUC is required to "consider the extent to which the electric utility has undertaken efforts to mitigate generation-related transition or stranded costs by appropriate means in a manner that is reasonable under all of the circumstances, including consideration of whether mitigation has been commensurate with the magnitude of the electric utility's generation-related transition or stranded costs." 66 Pa. C.S. § 2808(c)(4). In addition, and "of equal importance," the Commission is directed to "consider efforts undertaken over time, prior to the enactment of this Chapter to reduce or moderate customer rate levels while maintaining safe and efficient operations." 66 Pa. C.S. § 2808(c)(5). The purpose of this section of my testimony is to summarize PP&L's past and future mitigation efforts which have significantly reduced its stranded cost claim in this proceeding.

Q. Please explain your understanding and use of the term "mitigation" in this testimony.

A. I am using the term "mitigation" to describe any efforts by a utility to reduce costs or increase revenues (other than by rate increases), both historically and prospectively, and thereby reduce its stranded costs. Historic mitigation refers to past efforts to reduce costs and increase revenues. The effect of these historic efforts is reflected in the level of a utility's current rates and its corresponding level of stranded costs. Future mitigation refers to prospective plans and efforts during the transition period to competition and thereafter to reduce costs or increase revenues, which will further reduce a utility's stranded cost claim.

Q. Under the Act, both future and historic mitigation efforts are to be given equal consideration by the PUC. In your view, is this equal consideration of past and future mitigation appropriate?

A. It is not only appropriate, it is essential to any fair evaluation of a utility's claim for stranded cost recovery. Stranded cost, as defined in the Act, is essentially a measure of the difference between a utility's regulated cost of service and the market price for electricity. Those utilities who have been successful in controlling costs in the past will have lower current rates and correspondingly lower stranded costs. Conversely, those utilities with a higher cost of service will have higher rates and higher stranded costs. It is my belief that those utilities with high rates and high stranded costs should have more opportunity to "mitigate" stranded costs through future mitigation than utilities with lower costs and lower rates. Utilities with higher costs and higher rates also may be able to offer rate reductions and characterize these reductions as a "sharing" of stranded costs, even though their rates remain relatively high even after the reduction. On the other hand, utilities with lower costs and lower rates already have accomplished significant mitigation by controlling costs and have passed the benefits of lower costs through to ratepayers by maintaining lower rates over time. These past "mitigation" efforts must be considered and given equal weight in order to fairly evaluate a utility's stranded cost claim.

Q. Please describe PP&L's past efforts to reduce costs and maintain reasonable rates.

A. PP&L has an outstanding record of controlling costs and rates. Cost control and efficient management have been an integral part of the Company's corporate culture for many years. Although it would be impossible to provide an exhaustive list of these efforts, I have compiled some examples of PP&L's efforts to control costs and maintain reasonable rates. These efforts include refinancings, O&M cost reductions, reductions in planned capital expenditures, employee reductions, inventory reductions, cost-effective nuclear plant and fossil plant operations, reduced costs of NUG contracts and economic development initiatives.

Q. Please describe the cost reductions obtained through refinancings.

A. Since 1985, the Company has aggressively sought to refinance higher cost securities at lower rates. The Company's most recent base rate case used a September 30, 1995 test year. The rate case prior to that was based on a test year ended March 31, 1985. In that more than 10-year period, the Company's cost of debt was reduced by approximately 30%, from 11.27% (allowed in the 1985 case) to 7.97% (allowed in the 1995 case). The cost of preferred/preference stock over the same period was reduced from 9.89% to 7.31%. These capital cost reductions reduced the Company's revenue requirement in its most recent base rate case by almost $100 million.

Q. Please describe PP&L's efforts to control O&M costs.

A. After the Susquehanna Unit 2 rate case was decided in 1985, the Company undertook extensive efforts to avoid filing a base rate increase. These efforts included aggressive cost containment measures, elimination of unnecessary functions, restructuring at the corporate level and a re-engineering of critical processes. Although it is not possible to measure directly the specific savings achieved by these efforts, it is instructive to compare PP&L's O&M production costs over time adjusted for inflation. The following table shows PP&L's O&M production costs, excluding fuel, for 1986, 1986 adjusted for inflation and 1996.

	1986 FERC <u>Form 1</u>	1986 Adjusted for <u>Inflation</u>	1996 FERC <u>Form 1</u>
		(Millions $)	
Steam Production	$139.1	$189.0	$142.2
Nuclear Production	118.2	160.6	155.8
Hydraulic Production	6.1	8.3	6.3
Other Production	1.8	2.4	2.7
	$265.2	$360.3	$307.0

As this table shows, PP&L's O&M production costs have increased by only 16% from 1986 to 1996, and adjusted for inflation, have declined in real terms, by 15%.

Q. Please describe PP&L's employee reductions.

A. The Company has undertaken a continuous effort over an extended period of time to achieve cost reductions through more efficient utilization of employees. For example, in 1994, in an effort to reduce costs and improve operating efficiency, the Company offered an early retirement program to 851 employees who would reach age 55 by December 31, 1994. A total of 604 employees elected early retirement under this program. From the end of 1985 to the end of 1996, there has been an employee reduction of 2,005 regular full-time employees, or almost 24% of PP&L's 1985 workforce. Most of the reduction occurred through normal attrition, the early retirement program, a voluntary severance program or an equitable displacement policy.

Q. Please describe PP&L's inventory reduction efforts.

A. In 1991, the Company changed its method of accounting for spare parts at its power plants. Spare parts were previously expensed at the time of purchase. After the change, spare parts were recorded in an inventory balance sheet account. Although not required to do so, the Company changed its ratemaking treatment of spare parts between base rate cases, and passed back $94 million to customers over a five-year period through the Special Base Rate Credit Adjustment ("SBRCA"). Subsequent to this change in accounting method, the Company also undertook a thorough review to identify any obsolete or excess inventory. As a result of this review, the Company wrote off approximately $35 million of inventory. This has further mitigated the Company's stranded costs.

Q. Please describe the Company's planned reduction in capital expenditures.

A. In late 1995, the Company announced plans to reduce planned capital expenditures by $671 million over a five-year period. Included in this planned reduction was $486 million of expenditures for fossil generating plants. Reduced capital spending lessens the amount of the Company's unrecovered investment in generating facilities, its associated revenue requirements and, consequently, has mitigated the Company's stranded costs.

Q. Please describe the Company's mitigation efforts for its nuclear power plant.

A. A significant portion of the Company's stranded cost claim relates to the Susquehanna Steam Electric Station ("Susquehanna"). The Company has undertaken various measures that have resulted in a significant reduction in stranded costs associated with this facility.

The Company's efforts began while the plant was under construction. As explained in prior rate proceedings, the Company initiated an aggressive program to complete the Susquehanna plant as soon as possible, which significantly reduced its capital costs. As a result, the Company was able to construct two large nuclear units at a cost of about $3.6 billion for the Company's 90% ownership of 1,890 megawatts, or $1,900 per kilowatt. Other plants in Pennsylvania and around the United States which were under construction at the same time were significantly delayed in their construction and were completed at a significantly higher cost.

After the completion of the Susquehanna plant, the Company pursued certain claims against the containment supplier, General Electric. In 1991, the Company settled those claims. Because the cost of the plant already had been included in rate base, the Company, between rate cases, sought and obtained PUC approval to pass back to customers through the SBRCA the PUC jurisdictional amount of the proceeds from the settlement ($55 million).

The Company also has undertaken significant efforts to ensure that the Susquehanna plant operates with as high a capacity factor as possible. Nuclear power plants have high capital costs, but very low fuel costs.

Thus, the more the plant operates, the more fuel savings are generated. Susquehanna has had an outstanding operating record, and is recognized by industry organizations and the investment community as an efficient, well-run plant. This excellent operating record has reduced the Company's energy costs and customers' rates significantly.

To further increase Susquehanna's generation, the Company spent $45 million between 1991 and 1995 to uprate Susquehanna's capacity by 90 mw, or a cost of $500 per kw. This has produced significant additional energy cost savings to customers.

Q. Please describe the Company's past mitigation efforts for its fossil generating plants.

A. The Company has undertaken significant expenditures to maintain the availability of its low cost coal-fired generating stations and to extend their useful lives. This has benefited customers through lower fuel costs, increased interchange sales and lower rates. One specific recent example is the project to convert the Martins Creek 3 and 4 units to gas/oil co-firing. This project has permitted the Company to burn both gas and oil at this plant, which has increased the cost effectiveness of this plant.

Q. Please describe the Company's efforts to mitigate NUG contract costs.

A. Under PURPA, the Company was compelled to enter into long-term supply contracts with non-utility generators. Although the rates in these agreements were based upon expected future market prices at the time the contracts were signed, the contracts have turned out to be significantly above the Company's avoided cost and current market prices. In an effort to reduce the level of this stranded cost, the Company has undertaken several actions.

In March 1988, the Company took steps to minimize future NUG contracts by limiting its "Pioneer Rate," the rate paid to NUGs at that time. The Pioneer Rate provided a flat 6¢ per kilowatt hour sale for all NUG output. In 1988, the Company proposed to limit the availability of the rate to project developers who contracted with the Company prior to March 1988 and who actually signed an agreement on or before January 1, 1990. The Commission approved this proposal with minor modifications.

In 1995, PP&L agreed to a settlement of litigation before the Commission which effectively renegotiated the Paxton Creek NUG contract. The new agreement reduced the term of the power purchase agreement from 15 to 7 years and effectively converted Paxton Creek from a base load unit to a peaking unit.

In 1996, the Company bought out the contracts for the Continental and Archbald NUGs. These facilities represent 118.5 mw or 25% of the 474 mw of large NUG units under contract to PP&L. The buy-out agreements are structured to produce substantial savings as compared to the level of projected future payments under the power purchase agreements. The PUC approved the Continental buyout in January 1997. The Archbald agreement currently is being reviewed by the Commission. The effect of these agreements on stranded costs is discussed in the future mitigation section of my testimony.

The Company also has conducted extensive audits of existing NUG contracts to monitor compliance with terms and conditions of the contract. As a result of these audits, legal action was initiated in one particular case for noncompliance. If this litigation is successful, the Company's NUG contract costs will be reduced by approximately $10 million per year.

Q. Please describe the Company's economic development programs.

A. On the revenue side of the equation, the Company has made major commitments to economic development in order to retain existing industry and to attract new businesses to its service territory. These measures include interruptible service rates, Economic Development Initiative ("EDI") credits, Industrial Development Initiative ("IDI") credits and Demand Free Days. In addition, the Company has been involved nationally in prospecting to attract new industries, has been involved in numerous cooperative efforts with regional economic development organizations and has provided loans for economic development initiatives. These initiatives have enhanced the Company's revenues, helped PP&L to avoid rate increases and have helped generate thousands of new jobs in the Company's service territory. Although increasing sales, the Company also has established conservation, load management and demand-side management programs designed to promote more efficient and cost-effective use of electricity by its customers.

Q. What has been the net result of these past mitigation efforts?

A. The bottom line result is lower rates to customers and lower stranded costs. Although it is not possible to quantify the precise savings achieved through these past mitigation efforts, I believe it is instructive to place PP&L's rates in perspective over time and to compare those rates to the rates of other utilities.

PP&L's average rate in 1996 was 7.38¢/kWh which is only slightly above the 1986 average rate of 7.34¢/kwh coming out of the Susquehanna 2 rate case in 1985. Thus, PP&L's rates have declined, in real terms, by over 25% since 1986, as measured by the GDP Implicit Price Deflator. Given the initial 54-month rate cap contained in the Act, this real price decrease will likely continue. Assuming that rates today remain in place through June 2001, and assuming 2.5% annual inflation, PP&L's rates will have declined, in real terms, by approximately 34% since 1986.

Q. How do PP&L's rates compare to those of other electric utilities?

A. A detailed description of this subject is addressed in the testimony of Dr. Susan Tierney. In summary, based on 1996 data, PP&L's rates were approximately 7% below the Pennsylvania average.

Q. Why is the relative level of PP&L's rates important?

A. PP&L's rate levels are relevant for several reasons. Lower rates mean lower stranded costs and demonstrate the Company's aggressive past mitigation efforts. As explained above, these efforts should be fully considered in this proceeding in determining the level of stranded cost recovery.

Further, PP&L's current rate levels demonstrate that PP&L has been doing for years what the current proposal for competition is supposed to spur high cost utilities to do -- cut costs, operate efficiently and pass those savings on to customers.

Finally, a review of the restructuring activity in other states indicates that these proposals often include requests or mandates for significant rate reductions, i.e., 10% to 20%, as a condition for recovery of stranded costs. As demonstrated in Dr. Tierney's testimony, the existing rate levels in these states are significantly higher than PP&L's rates. Even with 10% to 20% rate reductions, the rates of those utilities would still be significantly above PP&L's existing rates. PP&L has done an outstanding job of maintaining reasonable rate levels for its customers through a combination of aggressive efforts over an extended period of time. Those efforts should be considered and given full credit in this proceeding.

Q. Has PP&L included the effects of any future mitigation efforts in its filing?

A. Yes. The Company has included additional cost reductions designed to reduce further its stranded cost claim. In addition, the Company is proposing a depreciation swap between generation and transmission/distribution facilities.

Q. Please describe the projected cost reductions included in PP&L's claim.

A. As noted above, in late 1995, the Company announced plans to reduce planned capital expenditures by $671 million over a five-year period. The associated reductions in revenue requirement reflected by this reduction have been incorporated into the Company's stranded cost calculation. The Company has projected approximately $513 million of unspecified reductions to future O&M and A&G costs. Similarly, the NUG buyouts referenced above are not reflected in PP&L's current rates and reduce stranded costs by $100 million. The net savings from these proposals have been removed from the Company's stranded cost claim, even though these savings have not yet been achieved. In other words, the Company and its shareholders will be at risk for achieving these savings.

Q. Please address the Company's proposal regarding reallocation of depreciation reserves.

A. In its 1995 rate filing, the Company filed for and was granted the right to extend the lives of its transmission and distribution plant. Had the Company used these longer lives when the transmission and distribution facilities were originally placed into service, the accumulated depreciation for these facilities would have been less than what is currently recorded on the Company's books. The Company proposes to take the $205 million difference between the current actual accumulated depreciation and theoretical accumulated depreciation and transfer it to accumulated reserve for depreciation associated with the Susquehanna plant. This exchange of excess depreciation reserves reduces the net plant balance for Susquehanna by approximately $205 million and reduces the Company's stranded cost claim by $317 million.

Q. What is the effect of these future mitigation efforts described above?

A. As explained in Mr. Schadt's testimony, the effect of the reduction in the growth rate of operations and maintenance costs at the nuclear and fossil generating plants and cost reductions in administrative and general activities, the two NUG buyouts, the reallocation of depreciation reserves, and a reduction in planned capital expenditures is to reduce the Company's stranded cost claim by over $1 billion.

Q. Are there other mitigation efforts you wish to address at this time?

A. Yes. As explained in Mr. Schadt's testimony, the Company's net mitigated stranded cost claim is $ 4.611 billion. As explained in Mr. Krall's testimony, by applying the CTC and rate cap provisions over the next nine years, the Company anticipates collecting $4.210 billion of its stranded cost. The remaining $401 million would not be collected from customers and would be absorbed, all else equal, by the Company's shareholders.

In addition, I should emphasize that the Company's stranded cost claim is based upon a projection of future market prices and assumes that a significant portion of the utility stranded cost will be recovered by way of increased market prices for electricity. This increase in market price may or may not occur, thereby placing the Company at risk for significant non-recovery of those stranded costs.

Q. Does the recovery of stranded costs under the CTC give the Company the opportunity to mitigate its exposure to an accounting write-off?

A. Yes. As explained in Mr. Krall's testimony, the Company is proposing to hold rates at December 31, 1996 levels except for the SBRCA. As part of its Restructuring Plan and CTC recovery, the Company is requesting PUC approval to accelerate the amortization of regulatory assets and post-transition NUG costs in amounts to offset the scheduled reduction in Susquehanna depreciation in 1999, the end of the amortization of the costs of the voluntary early retirement program and the buyout of NUG contracts.

Q. Mr. Hill, one of the examples of mitigation listed in the Act is the securitization of stranded costs. Is the Company proposing to securitize any portion of its stranded cost?

A. The Company is considering securitizing some portion of its stranded cost. However, the Company has not included an application for a qualified rate order as part of its restructuring filing in this proceeding. This should not be viewed as an indication that the Company is opposed to securitization or that the Company will not securitize a portion of its stranded cost and use that as a mechanism to reduce customer's rates to even lower levels.

Q. Why did the Company not include a request for securitization as part of its restructuring filing?

A. The current filing is a Restructuring Plan designed to unbundle the Company's rates, establish the terms and conditions for a competitive market and the Company's role in that market, set forth an estimate of the Company's stranded costs and a calculation of a competitive transition charge to recover those costs. The Company has not included a request for securitization at this time for several reasons. First, there is tremendous uncertainty at this time as to when and if the Company will be allowed to securitize stranded costs. The current PECO securitization proceeding has been highly contentious and based upon the Company's participation in that proceeding, it appears likely that the Commission's decision may be appealed by one or more parties. This would significantly delay the actual issuance of any transition bonds.

Second, there are several unresolved issues regarding tax matters, structure and accounting issues that require further review. It is apparent that securitization requires much more analysis than originally contemplated. Rather than rushing to include securitization in its restructuring filing, PP&L has elected to attempt to resolve these issues and to present a more definitive proposal to the Commission.

Third, the restructuring filing is itself complex and raises many important and novel issues. Given this likelihood of substantial delay, the Company decided not to needlessly complicate its restructuring filing with a securitization proposal at this time. The Company supports securitization, will continue to monitor the timing issues, and will advise the Commission as soon as its plans regarding securitization are more formalized.

FINANCIAL IMPORTANCE OF STRANDED COST RECOVERY

Q. Please describe the principles you believe should be applied in considering PP&L's stranded costs claim.

A. Stranded cost recovery will undoubtedly be a significant and controversial issue in this proceeding. The economic and policy reasons supporting stranded cost recovery are discussed in Dr. Kalt's testimony. In considering this issue, however, I feel that it is important for the Commission to keep in mind several important financial points.

First, the cost of the Company's generating facilities, including the generation-related portion of regulatory assets, was incurred as part of the Company's statutory obligation to provide reliable service to the Company's customers. The Company was required by federal law to enter into its current NUG contracts. The Commission has repeatedly reviewed the Company's base rates, and has included the cost of the Company's generating facilities in rate base and has approved recovery of regulatory assets. The Commission reviewed and approved recovery of NUG costs through the Company's ECR. The generating plants were built based upon the reasonable expectation that the Company would be provided with a fair opportunity to recover these costs in its rates. The NUG contracts were expressly conditioned upon a Commission Order that the Company would receive full and current recovery of these costs through its ECR or future equivalent. In my opinion, it would be fundamentally unfair and unreasonable to disallow recovery of prudent and reasonably incurred stranded costs. The Act appropriately recognizes this and provides an opportunity for reasonable stranded cost recovery.

Second, the amount of stranded cost recovery permitted in this case will have a significant impact on the Company's overall financial condition. While the Act calls for an "unbundling" of the generation, transmission and distribution functions, PP&L will continue to be the transmission and distribution provider to its existing customers and will be the generation supplier of last resort to its customers who do not elect to purchase their electricity from alternative suppliers. In order for PP&L to fulfill these obligations, it must have reasonable financial health that will allow it to attract capital on fair and reasonable terms. This is essential for PP&L to make ongoing investments necessary to serve its customers safely and reliably as the transmission and distribution supplier and to secure reasonable cost generation supplies for those customers as to whom PP&L remains the supplier of last resort.

Third, the Commission should carefully consider PP&L's extensive past and future efforts to mitigate stranded costs. These efforts, which are explained in detail above, have significantly reduced PP&L's stranded costs and demonstrate PP&L's commitment to a reasonable sharing of stranded costs. As noted above, PP&L's past mitigation efforts have produced rates which are below the Pennsylvania average. This demonstrates PP&L's efforts to control costs and produce reasonable rates for its customers. PP&L's future mitigation plans, which have reduced its stranded cost claim by over $1 billion, further demonstrate its continued commitment to its customers.

Fourth, even if the Company's claim is approved, it still faces substantial risks and uncertainties. Under the rate caps imposed by the statute and the projections in this case, PP&L will fail to recover approximately $401 million of its net mitigated stranded costs.

Finally, the net result of stranded cost recovery in this case will be to permit PP&L to continue to charge rates equal to the rate caps imposed by the Act for the next nine years. Even under current low rates of inflation over the next nine years, PP&L's customers will likely see significantly declining rates in real terms under the Company's proposal. Increases in the cost of capital, O&M costs and capital additions in excess of those projected by the Company will largely be borne by the Company because of the rate caps. This will place further financial pressure on the Company.

In addition, a very significant portion of the Company's generation-related costs are projected to be recovered out of future market revenues, not out of the CTC. For these reasons, it is critically important that the Company be permitted to recover its stranded costs in this proceeding.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 3

Direct Testimony of Joseph M. Kleha

Q. Please state your full name and business address.

A. Joseph M. Kleha, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) in its Office of General Counsel as Manager - Regulatory Projects.

Q. What are your duties as Manager - Regulatory Projects?

A. I am responsible for overseeing corporate projects involving regulatory agencies. As part of this function, I review and provide technical oversight on the preparation of the Company's cost allocation and revenue requirements studies.

Q. What is your educational background?

A. I graduated from the Pennsylvania State University in 1974 with a Bachelor of Science Degree in Accounting. I also have taken specialized courses dealing with public utility accounting and depreciation. In addition, I attended the NARUC Regulatory Studies Program in the summer of 1979.

Q. Please describe your professional experience.

A. I was employed by the Pennsylvania Department of Public Welfare as Field Auditor and Institutional Collections Officer from 1974 to 1977. In

1977, I joined the technical staff of the Pennsylvania Public Utility Commission ("PUC") as a Utility Rate Analyst in the Bureau of Rates and Research. In this position, my responsibilities included review of proposed retail electric rate filings and the preparation and presentation of testimony in formal rate proceedings. This testimony primarily dealt with the allowable levels and jurisdictional allocations of claimed operating revenues, operating expenses, and rate base. In July 1981, I joined PP&L as a Senior Accountant with responsibility for assembling financial data and preparing revenue requirement studies to support the Company's retail and wholesale rate filings. I was named Manager - Regulatory Projects, the position I now hold, in January 1990.

Q. Have you previously testified as a witness on cost-of-service-related issues?

A. Yes. As an analyst in the Commission's Bureau of Rates and Research, I offered testimony in the following rate proceedings:

Company	Docket No.
Duquesne Light Company	R-79010740
UGI Corp. - Luzerne Division	R-79050863
Philadelphia Electric Company	R-79060865
West Penn Power Company	R-80021082
Pennsylvania Power & Light Co.	R-80031114

Metropolitan Edison Company	R-80051196
Pennsylvania Electric Company	R-80051197

As an employee of PP&L, I have offered testimony in the following rate proceedings before the PUC and the Federal Energy Regulatory Commission (FERC):

Docket No. I-900005	Docket No. ER88-545-000
Docket No. P-910521	Docket No. ER91-322-000
Docket No. M-00930406	Docket No. ER95-1267-000
Docket No. C-00935175	Docket No. ER96-930-000
Docket No. C-00935403	Docket No. ER96-931-000
Docket No. R-00943271	Docket No. ER96-932-000
Docket No. C-00957559	Docket No. ER96-933-000
Docket No. P-00961023	Docket No. ER96-1428-000
Docket no. C-00967591	Docket No. SC97-1-000
Docket No. C-00967955	
Docket No. C-00968035	
Docket No. P-00961114	

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

A. My testimony and accompanying exhibits describe and support the Company's calculation of base year retail rate base and operating revenues; development of the cost allocation study which forms the basis for approved retail rates; determination of retail jurisdictional costs and revenue requirements; unbundling of the retail cost of providing service and applicable revenue requirements into functional components; calculation of the Energy Cost Rate ("ECR") roll-in; proposed treatment of nuclear decommissioning costs in the Competitive Transition Charge ("CTC"); and reconciliation of the CTC.

Q. Are you responsible for any of the Company's responses to the Commission's filing guidelines submitted in Exhibit No. 2.

A. Yes. I am responsible for responses to the following Commission filing guidelines: RP-A.3., A.4., A.6., A.7., C.17., F.1., F.14., I.1., I.4., I.5., I.8., I.9., I.18., L.5., L.12., L.13., L.14, and L.15.

Q. What base year is the Company utilizing in this proceeding?

A. The Company is using the 12 months ended December 31, 1996 as the base year.

Q. How is the base year data utilized in this proceeding?

A. The base year data constitutes the starting point for computation of the Company's stranded costs, development of the CTC and design of unbundled rates.

Q. What is the source of the Company's base year data?

A. The base year data reflected in this filing are taken directly from the Company's books and records.

Q. Is the Company proposing any adjustments to the base year data?

A. Yes. The Company is proposing a number of adjustments to the base year data to reflect a normal level of operations.

Q. Are you responsible for any of these adjustments?

A. Yes. I am responsible for the adjustment to rate base and the three adjustments to operating revenues.

Q. Please discuss the Company's proposed adjustment to base year rate base.

A. In accordance with the policy established by the Commission, the Company reduced its base year rate base to reflect the cash working capital hypothetically available from payments of interest on long-term debt and payments of dividends on preferred stock.

Q. Please describe the three adjustments to base year operating revenue.

A. The first adjustment annualizes sales for changes in customer usage and growth. The second adjustment to base year revenue eliminates unbilled base rate revenue, a non-recurring ECR interest refund and a PJM billing adjustment. The third adjustment to base year revenue weather-normalizes sales billed during calendar year 1996. All of the adjustments are shown in PP&L's Financial Report for the 12 Months Ended December 31, 1996. This report, which was filed with the PUC pursuant to its regulations at 52 Pa. Code § 71.1 <u>et seq</u>., is provided as Attachment 1 of the response to the Commission's filing guideline at Appendix A, Section A, Item 3.

Q. Are you sponsoring any additional exhibits in this proceeding.

A. Yes. I am responsible for Exhibit JMK 1, Exhibit JMK 2 and Exhibit JMK 3.

Q. Would you briefly describe the contents of Exhibit JMK 1?

A. Exhibit JMK 1, which is provided in response to the Commission's filing guideline at Appendix A, Section I, Item 1, presents a fully distributed allocation of the Pennsylvania jurisdictional costs of providing electric service to PP&L's various retail rate classes. The study contained in Exhibit JMK 1 is based on costs and operating conditions for the 12 months ended September 30, 1995 and represents PP&L's compliance with the results of the Commission's Final Order in the Company's most recent base rate proceeding at Docket No. R-00943271. Exhibit JMK 1 provides a summary of the allocation process results, a computer printout of the cost allocation study and supporting schedules which show assignment of costs, and the various allocation factors used. Explanatory materials regarding assignment techniques employed also are included.

Q. What allocation method was utilized in the Company's cost allocation studies?

A. The Company's cost allocation studies follow the same allocation principles utilized by PP&L in its most recent base rate filing at Docket No.

R-00943271. As explained in Exhibit JMK 1, PP&L employs the monthly peak responsibility demand allocation method, or 12 coincident peak method (12 CP), which is based on the average of the twelve monthly class demands coincident with the time of the system monthly peak loads. The Company believes that, for its system, this method is a reasonable and appropriate methodology for the allocation of its demand-related costs. This cost allocation methodology was accepted by the Commission at Docket No. R-00943271, and in numerous prior retail base rate proceedings.

Q. Please explain how the Company's Pennsylvania jurisdictional costs are derived.

A. This filing is based on the costs incurred to provide service to Pennsylvania jurisdictional customers. Section III of Exhibit JMK 1 provides the allocation of total electric costs between the Federal (wholesale) and Pennsylvania (retail) jurisdictions. The result is that all costs associated with the bulk power supply services to Atlantic City Electric Company ("ACE"), Baltimore Gas & Electric Company ("BG&E"), Jersey Central Power & Light Company ("JCP&L"), and UGI Utilities, Inc. ("UGI"), as well as the full requirements wholesale services to Citizens' Electric Company of Lewisburg, the Allegheny Electric Cooperative, Inc. and sixteen municipalities are excluded from PUC jurisdictional revenue requirements.

Q. Please describe Exhibit JMK 2.

A. Exhibit JMK 2 contains the studies supporting the Company's proposed functional unbundling of its costs of providing PUC jurisdictional electric service into their constituent elements. Unbundling of costs begins with PP&L's cost allocation study, which complies with the results of the Commission's Final Order at Docket No. R-00943271, contained in Exhibit JMK 1, which I just described. All costs included in Exhibit JMK 1 and upon which approved rates are based were assigned and allocated to the applicable functional cost categories: Energy, Other Production, Transmission and Distribution. Section III of Exhibit JMK 2 contains the details of this unbundling.

The data contained in each of the four summary columns in Section III are inserted into a separate allocation program which assigns the unbundled functional cost categories to the Company's various retail rate classes. Sections IV, V, VI and VII show the details of these calculations. In each section, the revenue requirements developed at class rates of return are used as the basis for rate development. A summary of these results is shown in Section II of Exhibit JMK 2.

Q. Please describe the distribution plant investment studies contained in Exhibit JMK 3.

A. Exhibit JMK 3 contains the results of two studies: (1) the subfunctionalization of distribution plant investment and expense into primary and secondary voltage components and the classification of the secondary components into customer and demand-related costs, and (2) the development of allocators for meter investment and meter reading expense, which are used in the cost allocation study provided in Exhibit JMK 1. It should be noted that the subfunctionalization and classification of distribution plant investment and expense is based on a detailed analysis of specific PP&L plant records and cost data. In classifying its distribution plant investment and operating expenses into customer and demand-related costs, PP&L used the "minimum size system" method to identify the applicable cost components. The methodologies employed in the studies are explained in detail in Exhibit JMK 3 and the results of these studies are reflected in Sections A and B of Exhibit JMK 1.

Q. Are you familiar with the Company's proposal to roll its ECR into base rates?

A. Yes.

Q. Please summarize that proposal.

A. On December 13, 1996, PP&L filed an application with the PUC requesting permission to roll into base rates its ECR and State Tax Adjustment Surcharge ("STAS"). PP&L made this filing in response to the Electricity

Generation Customer Choice and Competition Act ("Act"), particularly Section 2804(4) of the Act which establishes certain caps on utility rates.

In its filing, the Company also requested that the Commission determine that two categories of costs are "regulatory assets" or "other deferred charges" that are recoverable as "transition or stranded costs" under the Act. The first category is PP&L's actual undercollected energy costs as of December 31, 1996. The Company initially estimated that its ECR undercollection as of December 31, 1996 would be approximately $13.9 million. PP&L committed to update this estimate to reflect actual costs prior to including those costs as "transition or stranded costs" in its Restructuring Plan. The second category is a normalized level of estimated future on-going energy costs. The Company estimated that its normalized level of future on-going energy costs would be approximately $31.5 million higher than the level of energy costs rolled into base rates. PP&L calculated this amount by taking an average of actual energy costs for a 5-year period from 1992 through 1996 and subtracting the level of energy costs included in jurisdictional base rates after the ECR roll-in.

The Company emphasized that it was not seeking a determination of the prudence of its energy costs for the period ended December 31, 1996. The Company requested only a determination that the costs identified above would be classified as a "regulatory asset" or "other deferred charge" and would be recoverable as a "transition or stranded cost" in its Restructuring Plan.

Q. Did the Commission approve the Company's ECR roll-in?

A. Yes. In a tentative order entered December 19, 1996 at Docket Nos. P-00961131 and R-00963842, the Commission fully approved the Company's application.

Q. Please describe the impact of the ECR roll-in on this Restructuring Plan filing.

A. The Commission's approval of the Company's ECR roll-in created two regulatory assets. The first, which represents PP&L's actual undercollected energy costs at December 31, 1996, is $17.2 million. The second, which represents a normalized level of future on-going energy costs, is approximately $31.5 million on an annual basis.

Q. Has Mr. Schadt reflected this impact in his calculation of the Company's stranded costs?

A. Yes. As shown in Exhibit JRS 1, these two regulatory assets are reflected in the Company's stranded cost calculations. The regulatory asset associated with undercollected energy costs is reflected only in 1997. This undercollection is not a recurring item and should be recovered only once. The regulatory asset associated with a normalized level of future on-going energy costs is reflected in 1997 and 1998. Based on the Company's normalization calculation, it will experience an undercollection of its on-going energy costs every year from the date of the ECR roll-in until the beginning of the CTC period.

Q. Please explain the potential impact of the Act on PP&L's recovery of nuclear decommissioning costs.

A. The transition to full competition raises two related concerns regarding PP&L's recovery of nuclear decommissioning costs. First, there is some concern regarding whether the Act will provide for adequate recovery of nuclear decommissioning costs. Specifically, the Act provides electric utilities with an opportunity to recover "stranded costs" through the CTC over a nine-year period, including those nuclear decommissioning costs that may not be recoverable in a competitive generation market. As a result, PP&L will have to fund a significant portion of its nuclear decommissioning costs out of revenue from market rates. These market rates provide no assurance that revenues will be sufficient to meet PP&L's funding obligations for nuclear decommissioning.

Second, there is a risk that PP&L may become subject to substantial financial qualification requirements under Nuclear Regulatory Commission ("NRC") regulations. NRC regulations allow "electric utilities" to provide financial assurance for decommissioning by establishing an external sinking fund without additional surety or insurance. The NRC's rules define "electric utilities" as "any entity that generates or distributes electricity and which recovers the cost of electricity, either directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." 10 C.F.R. §50.2.

As a utility with rates set by the PUC on the basis of the Company's cost of providing electric service, PP&L clearly has met the NRC's definition of an "electric utility" under traditional rate regulation. Under current rates set by the PUC, PP&L is authorized to recover the estimated future cost of nuclear decommissioning in current rates over the life of the Susquehanna generating plant. These recovered costs are deposited into an external trust fund. However, the unbundling of the generation function from the regulated transmission and distribution functions arguably will remove costs related to Susquehanna from traditional "cost-of-service" ratemaking. Moreover, as I explained earlier, there is some concern regarding whether a portion of PP&L's nuclear decommissioning costs will have to be recovered through market rates after the CTC expires.

Therefore, it is possible that, following the transition to competition, the NRC will determine that the Company's nuclear decommissioning costs are not recovered through rates established by the PUC. This determination could cause the NRC to reconsider PP&L's status as an "electric utility" exempt from decommissioning financial assurance requirements. If PP&L were to lose its status as an "electric utility," it might have to pre-fund the entire cost of decommissioning Susquehanna or, at a minimum, provide some form of insurance or other surety for future decommissioning trust fund collections. Either option would have a significant financial impact on PP&L and would increase the level of its stranded costs.

Q. Please describe PP&L's proposed solution to address the concerns you have just described.

A. The Company proposes to address these two concerns by extending the CTC beyond the nine-year window provided by the Act to permit recovery of its nuclear decommissioning costs over the remaining life of the Susquehanna generating plant. Section 2808(b) of the Act specifically permits the PUC to extend the nine-year term of the CTC for "good cause shown." PP&L believes that its proposal to extend the CTC clearly meets this standard for several reasons.

First, unlike most other stranded costs, nuclear decommissioning cost funding is an important public health and safety issue. The PUC has consistently recognized the importance of adequate funding for future decommissioning costs and has consistently approved the advanced funding of nuclear decommissioning costs since the 1970s.

Second, PP&L's proposal would ensure that its nuclear decommissioning costs will be recovered through rates set by the PUC. As such, PP&L's proposal would enable the Company to retain its status as an "electric utility," thereby eliminating an NRC requirement to pre-fund or insure decommissioning costs. Avoiding these requirements would reduce the level of PP&L's stranded costs to the benefit of both PP&L and its customers.

Third, the Company's proposal will ensure adequate nuclear decommissioning funding both during and after the transition to retail competition.

Finally, it is important to note that the charge resulting from PP&L's proposal would be extremely small and its impact on customers will be minimal. For example, PP&L is currently collecting approximately $9.5 million per year in jurisdictional rates for nuclear decommissioning costs. For the average residential customer using 500 kilowatt-hours per month, this amounts to 0.03¢/kwh, which is about $0.15 per month and less than $2.00 per year.

Q. Are you generally familiar with the Company's proposed CTC?

A. Yes.

Q. Please briefly describe the purpose and operation of the CTC.

A. The CTC is the mechanism, provided for in Section 2808(f) of the Act, through which a utility is permitted to recover its stranded costs. It is a non-bypassable monthly charge that must be paid by every customer connected to the distribution utility company's system. The CTC may be different each year and may be different for each customer or customer class. The CTC can be billed to customers in the form of a fixed customer charge, a per-KW demand charge or a per-KWH energy charge, or any combination of these alternatives.

Q. Should collections under the CTC be "trued-up" or reconciled?

A. Section 2808(f) of the Act calls for a limited true-up of the CTC to reconcile CTC revenues with the CTC-recoverable costs approved by the Commission. The Act does not contemplate a recalculation of stranded costs collected through the CTC. The reconciliation contemplated by the Act appears to be limited to a true-up for changes in sales from the level of sales that the Commission uses to establish the CTC initially. Under this approach, the utility and its customers would be assured that the collection of stranded costs through the CTC would track the Commission's order. At the same time, this approach could be implemented in a relatively simple manner which would not lead to re-litigation of the many complex issues raised in the utility's original Restructuring Plan filing.

Q. Please discuss the concern that you have identified regarding CTC reconciliation.

A. In its initial analysis, the Company considered recommending an annual CTC reconciliation procedure similar to the annual ECR reconciliation procedure that has been in place in Pennsylvania for many years. However, this approach raises a significant concern. For example, assume that a utility's rates (including the CTC) are exactly at its rate cap level. Also, assume that the utility undercollects its CTC in year one. Under an ECR-type reconciliation process, the utility would be entitled to recover that undercollection in year two. However, because the utility's rates already are at its rate cap level in year two, it would not be permitted to recover the undercollection. Presumably, it would be forced to forego that amount of its CTC.

Q. Please describe the Company's proposed procedure for reconciling the CTC.

A. The Company is proposing the following approach: A utility would track its annual collections under the CTC and compare those annual collections with the CTC collection levels authorized by the Commission. All undercollections or overcollections would be tracked by the utility, subject to Commission review and verification. During the term of the CTC, the tracking of overcollections and undercollections would not lead to a change in the

CTC rate. However, near the end of CTC application period, the utility would calculate the net amount of the overcollections and undercollections which occurred during the entire term of the CTC. The final termination date of the CTC would be adjusted to provide for a full refund of any overcollections and a full recovery of any undercollections. Accordingly, if a utility experienced a net undercollection during the term of the CTC, the termination date of the CTC would be extended to permit the utility to recover those amounts. On the other hand, if a utility experienced a net overcollection during the term of the CTC, termination of the CTC would occur sooner. In this way, Pennsylvania electric utilities and their customers would be assured that the amount of stranded costs recovered through the CTC is neither greater than nor less than the amount authorized by the Commission. Moreover, this approach avoids the rate cap concern and other concerns associated with an actual change in the CTC rate each year to account for undercollections and overcollections. Admittedly, this approach could extend the term of the CTC to more than nine years, but it also could shorten the CTC term if overcollections occur. Unless a utility experiences a major change in load, it is expected that these variations in the term of the CTC will be minimal. The Act specifically authorizes the Commission to change the CTC collection period "in its discretion and for good cause shown." I believe that the Company's proposed reconciliation procedure provides good cause for varying the length of the CTC.

Q. Does that conclude your direct testimony?

A. Yes.

Q. Please state your full name and business address.

A. Michael J. Berish, Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am employed by the Pennsylvania Power & Light Company (PP&L or the Company) as Team Leader-Business Planning.

Q. What are your responsibilities as Team Leader-Business Planning for PP&L?

A. I am responsible for coordinating the development of financial operating plans for the Company's various departments, administering its functional group (cost area) budget control system and various special studies.

Q. What is your educational background?.

A. I graduated in 1967 from the Pennsylvania State University with a Bachelor of Science Degree in Accounting. I also received a Masters Degree in Business Administration from Lehigh University in 1971.

Q. How long have you been employed by PP&L and in what capacities?

A. I joined PP&L in 1967 as a Methods Accountant in the Data Processing Division of the Financial Department where I worked as a computer programmer until 1969. From 1969 to 1973, I was a Systems Analyst and later a Senior Systems Analyst in the Division Operations Department where I was responsible for analyzing clerical systems with a goal of making them more efficient or computerizing them. From 1973 to 1975, I was a Fuel Adjustment Specialist in the System Power & Engineering Department, where my duties were to analyze the fuel costs recovered through the fuel adjustment clause. In 1975, I was appointed Supervisor-Financial Planning in the Financial Department, and in 1979 was appointed to Manager-Financial Planning. In 1996, I was named to my present position.

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

A. My testimony describes and supports the Company's accounting and other financial data submitted in response to the filing guidelines for Electric Utility Restructuring established by the Commission in its order at Docket No. M-00960890. The Company's responses to these filing guidelines are provided in Exhibit No. 2.

Q. What specific information are you sponsoring?

A. The Commission's order requires all utilities to use a pro forma base year ended December 31, 1996. PP&L's base year financial data is provided as Attachment 1 to Appendix A, Section A, Item 3. The first page of this attachment provides a summary of Rate Base, Income Available for Return and Rate of Return. Within the Rate Base category, I am sponsoring the data under the column heading "Actual per Books" for Materials & Supplies and Fuel Stocks (Line 5); Cash Working Capital (Line 6); Liberalized Depreciation (Line 9); Customer Advances (Line 12); and, Customer Deposits (Line 13). Within the section for Income Available for Return, I am sponsoring the data under the column heading "Actual per Books," for Operating Revenues (Line 17) and all Operating Expenses (Lines 18 through 24). I also will describe and support all of the operating expense adjustments listed under the column heading "Pro Forma Intrastate Adjustments," except for the annual depreciation adjustment.

Q. Please describe the source and method used to establish the book cost figures shown in the Company's books of account.

A. The accounts of the Company are kept in accordance with the Uniform System of Accounts prescribed by the PUC and the FERC for Electric Utilities and Licensees.

Q. Are these accounts audited?

A. They are audited annually by an independent certified public accounting firm. In addition, the FERC and PUC audit staffs conduct periodic audits of the Company's books and records.

Rate Base

Q. Mr. Berish, the base year Rate Base includes an amount for "Materials & Supplies and Fuel Stocks." Please explain this item.

A. This item reflects the amount invested in coal and oil used as fuel at PP&L's various generating stations, as well as the materials and supplies stored principally at power plants and service area storerooms to supply line crews. These values are increased by the fuel stock expense applicable to the various fuels, which is principally the cost of purchasing and other procurement expense of the fuel in inventory and storeroom expenses for the materials and supplies inventory.

The amount for materials and supplies and fuel stocks is based on a 13-month average of the various items included in Accounts 151, 152, 154 and 163.

Q. The base year rate base shows an amount for "Cash Working Capital." Would you explain this amount?

A. This amount represents the Company's average investment in cash working capital. There are three major components in this item: cash working capital required for operation and maintenance expenses; funds invested in prepayments; and accrued taxes.

Q. Would you explain these three components?

A. The first component is cash working capital required for operation and maintenance expenses. The Company bills all of its customers once every month but the due date for payment varies between 15 and 30 days from the billing date. On this basis, there is a considerable lag between the time electricity is furnished to a customer and the time the customer pays for such electricity. This lag averages 35 days for customers with 15-day due dates, 42 days for customers with 20-day due dates, and 39 days for customers with 30-day due dates. Payments received for interchange sales lags the time electricity is delivered by an average of 35 days. The revenue lag from bulk power contracts and sales to UGI have 20 days and 17 days, respectively. The average lag in receipt of revenues from all these sources is 35.6 days on a dollar-weighted basis.

In most instances, the Company must pay its bills for payroll, fuel and other operating expenses prior to the time it is able to collect the amount due for the service that gives rise to these expenses. The Company has examined its records to determine, as to the major categories of expense, the average span of days between the time an expense is incurred and the time it must be paid. This lag ranges from 11 days to 46 days for various types of costs. The overall average for all expenses is 30.9 days. Thus, the average net lag between the payment of expenses and the receipt of the related revenue is 4.7 days (35.6 days less 30.9 days). To cover its expenses and continue to conduct its business during this time lag the Company must provide a cash investment.

The second major component of cash working capital is made up of funds which are invested in prepayments. In conducting its electric business, the Company must pay certain costs prior to the time such items are properly charged to expense for accounting and ratemaking purposes. For example, many insurance premiums must be prepaid, but are expensed monthly over the period to which they apply. Costs of this nature are initially charged to Account 165, Prepayments, and are subsequently charged to expense from this account.

The amount for prepaid expenses is based on a 13-month average of the various items included in Account 165.

The third major component of cash working capital is an amount for accrued taxes. In the case of Federal income tax, estimated payments must be made on April, June, September and December 15 of the year to which the tax is applicable. Because revenue is collected from customers monthly, there are funds temporarily available for payment of other costs. The Company's computations indicate that funds available from this source average 6.72 percent of the federal income tax due.

Presently, the Pennsylvania income tax and Pennsylvania capital stock tax have an effective pattern of required estimated payments as follows:

- 22.5 percent on March 15
- 22.5 percent on June 15
- 22.5 percent on September 15
- 22.5 percent on December 15
- 10 percent on April 15 of the following year

The Company's computations indicate that the funds available from these taxes average 11.72 percent of the tax due.

The Pennsylvania gross receipts tax must be paid on an estimated basis by March 15 with final payment due on March 15 of the following year. The Company's estimated payment on March 15 generally is equal to 90 percent of the final tax due. Revenue is collected from customers monthly and funds must be provided by investors to pay these taxes prior to collection of revenues from customers. The Company's computations indicate that the funds which must be provided for this purpose average 22.87 percent of the tax due. The amount for this tax item is based on the total Pennsylvania gross receipts tax which must be paid at the 44 mill rate actually in effect.

The Pennsylvania Public Utility Realty Tax must be paid on an estimated basis by April 15 with final payment due on April 15, of the following year. The Company's estimated payment on April 15 generally is equal to 90 percent of the final tax due. PP&L's computations indicate that funds which must be provided for this purpose average 14.53 percent of the tax due.

A calculation of these working capital components is provided as Attachment 1 of response to the Commission's filing guideline at Appendix A, Section A, Item 4.

Q. Please explain "Liberalized Depreciation."

A. Liberalized depreciation is the total of various deferred income taxes which have been established over time to reflect the difference between the calculation of taxes paid to the Federal government and taxes calculated for ratemaking purposes. They represent, in essence, a zero cost loan from the government. The carrying cost savings from deferred income taxes are passed back to customers through a rate base deduction equal to the deferred income tax balances.

Q. Please describe the Rate Base reductions for "Customer Advances" and "Customer Deposits."

A. Customer advances for construction represent the amounts provided by customers and recorded in Account 252 at December 31, 1996, pending completion of construction or conclusion of the period during which some portions may be refundable under tariff provisions and service contracts with those customers. The second item is Customer Deposits. These deposits are deducted from rate base in compliance with the Commission's Order at Docket No. R-80031114.

Q. Why aren't Accumulated Deferred Investment Tax Credits (as shown in Account 255) reflected in the computation of Rate Base?

A. Under provisions of the Revenue Act of 1971, public utilities were afforded the option of treating the investment tax credit in rate proceedings as a reduction of operating taxes over the life of the property and not deducting the accumulated amount of the credit from rate base. The Company made this election on March 8, 1972, and amortizes this tax credit to operating expense over the life of the related property.

Income Available for Return

Q. Mr. Berish, would you please explain the determination of book Operating Revenue?

A. Yes. Operating revenue is the revenue included in Accounts 440 through 456. It includes revenue from the sale of electricity to residential, commercial and industrial customers, streetlighting and public authorities, sales to other electric companies for resale, rentals of electric property, late payment charges, miscellaneous service revenue, and other revenue, e.g., unbilled revenue and PJM capacity credit amounts.

Q. What is included in the operating expense category?

A. Operating expense includes amounts for operation and maintenance expense, depreciation, income taxes, deferred taxes, investment tax credit, and taxes other than income.

The net of operating revenue and operating expense is the income available for return.

<u>Pro-Forma Adjustments</u>

Q. Turning to the adjustments to book data, please explain the adjustment for "Energy Costs."

A. This adjustment was made to normalize energy costs by eliminating a non-recurring credit to energy costs associated with a fuel oil refund received from the Department of Energy. This refund relates to purchases of petroleum products from various suppliers during the period August 1973 through January 1981.

Q. Mr. Berish, please explain the adjustment for "Wage Expense."

A. This adjustment normalizes wages. The total wages paid to all employees during the last three months of the base year were examined to determine the average wage per employee. The use of the three-month average was necessary to reflect the level of wages which were in effect at December 31, 1996. This average monthly wage was then multiplied by the total number of personnel employed at year end 1996. By multiplying the total monthly payroll by twelve months, the total annual wages were computed. From this amount was deducted the actual wages for the year. The difference was then multiplied by the portion charged to operating expense to arrive at the wage adjustment.

Q. Mr. Berish, please explain the adjustment for "Management Audit Expense."

A. This provides for the amortization over a five-year period of the costs of a comprehensive management audit required by the PUC. The audit was performed by Shumaker & Company. This amortization was approved by the Commission in its Final Order at Docket No. R-00943271.

Q. Will you please explain the adjustment for "Land Management/Recreational Facilities Expense?"

A. In its Final Order at Docket No. R-822169, the Commission determined that operation and maintenance expenses incurred for certain land management projects/recreational facilities which are not owned or operated pursuant to a specific Federal or State licensing requirement should not be reflected in rates. This adjustment provides for the elimination of the base year operating expense for such facilities.

Q. Will you please explain the adjustment for "Customer Deposits Interest Expense"?

A. Yes. This adjustment is for interest expense applicable to customer deposits. This adjustment is consistent with the Commission's policy of allowing appropriate interest expense when customer deposits are treated as a reduction to rate base. In this filing, PP&L has treated customer deposits as a reduction to rate base.

Q. Please explain the adjustment to "Annual Depreciation Expense."

A. Adjustments relating to annual depreciation expense will be explained by Mr. Hoch.

Q. Please explain the adjustment for "Interest Synchronization."

A. This is an adjustment to income taxes resulting from the annualized interest expense associated with intrastate pro forma results.

Q. Would you explain the adjustment for "R&E Tax Expense."

A. Yes. This adjustment was made to normalize base year income tax expense by eliminating a non-recurring credit associated with research and experimentation activities. This tax credit is based on prior period investments in technology and computer software.

Q. Are you responsible for any of the Company's other responses to the Commission's filing guidelines?

A. Yes. My name is indicated on those responses for which I am responsible.

A. Does this conclude your direct testimony?

A. Yes it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 5

Direct Testimony of Donald S. Hoch

Q. Please state your full name and business address.

A. Donald S. Hoch, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or Company) as Financial Specialist -- Depreciation / Systems.

Q. What are your duties as Financial Specialist -- Depreciation/Systems?

A. I am responsible for all policy and procedure issues related to book depreciation at PP&L. Included within my responsibilities are the preparation of service life studies using the retirement records of the Company to ascertain the average service life and dispersion characteristics of utility property. I also assist in the identification, development and implementation of computer systems for the Financial Department at PP&L.

Q. Please describe your educational background.

A. I am a graduate of Grove City College with a Bachelor of Science degree in mathematics and of Lehigh University with a Master of Science degree in Industrial Engineering with an emphasis on Information Systems. I also have participated in depreciation seminars for five years at Michigan Technological University and at Calvin College in Michigan, and in numerous

IBM courses and seminars concerning computer programming, system analysis and design, and computer-related topics.

Q. How long have you been employed by PP&L and in what capacities?

A. I was employed by PP&L in 1969. From 1969 through 1971, I worked in the Operations Research Section of the Company where my responsibilities were to design systems and computer programs for engineering, scientific and financial applications. This work primarily consisted of the development of a critical path method system that was used to schedule construction projects and allocate resources.

In 1971, I was assigned to assist in the redesign of the Company's Plant Accounting System, the associated data base of plant records and all the programs and related systems. This work included subsystems for actuarial and simulated plant record (SPR) life analysis studies, depreciation studies, the maintenance of Company trend and Iowa curve files, plant valuations, the depreciation reserve and a variety of other reports and records. This work also included the preparation of all trending and depreciation exhibits and studies that were filed in support of rate filings submitted to the Pennsylvania Public Utility Commission in 1969 (Docket No. C-18908), 1971 (Docket No. C-19244), 1973 (R.I.D. No. 84), 1975 (R.I.D. No. 221), 1980 (Docket No. R-80031114), 1981 (Docket No.

R-811636), 1982 (Docket No. R-822169), 1984 (Docket No. R-842651), and 1994 (Docket No. R-943271).

Subsequent to the redesign assignment, I developed and maintained several deterministic/probabilistic modeling systems, including a Company financial model, a general modeling system to simulate user-defined models and a model of future plant based on budget estimates. In September 1981, I assumed full responsibilities as Manager-Depreciation. In that position, I was responsible for all aspects of book depreciation, including preparation of depreciation studies using the retirement records of the Company to ascertain the average life and dispersion characteristics of electric property. These studies currently are used as a basis for calculating annual depreciation for accounting purposes, as well as both annual and accrued depreciation for rate studies.

In November 1994, I assumed the position of Supervisor-Plant Accounting. In that position, I was responsible for managing the maintenance of Company records of construction, plant in service and depreciation in accordance with Federal and State regulatory bodies and Company requirements. I also was responsible for providing timely information concerning the physical property of the Company to various corporate departments for use in studies and reports for management and regulatory bodies.

In February 1996, I assumed the position of Financial Specialist -- Depreciation / Systems.

Q. Have you participated in professional programs or educational projects other than those you previously mentioned?

A. I am a member of the Property Accounting & Valuation Committee of the Edison Electric Institute. I have received certification in data processing (C.D.P.) from the Institute for the Certification of Computer Professionals.

Q. What is the purpose of your testimony?

A. I will explain the Company's base year amounts for the original cost of utility plant in service, accrued depreciation and annual depreciation expense. These amounts are set forth in Attachment 1 of the Company's response to the Commission's filing guideline at Appendix A, Section A, Item 3.

Q. Are you responsible for any other responses to the Commission's filing guidelines submitted in Exhibit No 2?

A. Yes. Under the caption entitled Depreciation, I am responsible for the following guidelines: RP-E.1., E.2., E.3., E.4., E.5., E.6., E.7. and E.8. Under the caption entitled Rate Base, I am responsible for the following guidelines: RP-F.1., F.7., F.10., F.11., F.12., F.13. and F.18. Under the caption entitled Restructuring Issues, I am responsible for the following guideline: RP-L.5.

Q. Mr. Hoch, were these responses prepared by you or under your supervision?

A. They were prepared under my direct supervision.

Q. Please summarize the major components of the Company's original cost of utility plant-in-service, accrued depreciation and annual depreciation expense.

A. The following is an enumeration of the key plant or depreciation items in this filing:

1. ORIGINAL COST MEASURE OF VALUE

PP&L is basing its rate base on the original cost measure of value.

2. TRANSMISSION, DISTRIBUTION AND GENERAL PLANT AVERAGE SERVICE LIVES, RETIREMENT DISPERSIONS, AND ANNUAL DEPRECIATION RATES

For all plant accounts in these functions, the average service lives, retirement dispersions and/or amortization periods are based on a service life study completed in 1993. That service life study was accepted by the Commission in the Company's most recent retail base rate filing at Docket No. R-00943271. The actuarial techniques used in that study are the same as those employed in a prior service life study which was accepted by the Commission at Docket No. R-842651. The calculation of the annual accruals reflects the application of the service life parameters from the service life study and the straight-line remaining life method of depreciation. In its Order at Docket No. P-880332, the Commission instructed the Company to change from the whole-life technique to the remaining life technique, effective January 1, 1989.

3. STEAM PRODUCTION, NUCLEAR PRODUCTION, HYDRO PRODUCTION AND OTHER PRODUCTION INTERIM SURVIVOR CURVES

The interim survivor curves used as a parameter of the life-spanning depreciation system for power production facilities in Steam Production, Nuclear Production, Hydro Production and Other Production are based on an interim retirement study completed in 1993. This study was accepted by the Commission at Docket No. R-00943271. A prior interim survivor study, which used the same analytic techniques as the current study, was accepted by the Commission at Docket No. R-842651.

4. POWER PRODUCTION UNIT DEACTIVATION DATES

The deactivation dates and resulting life spans used for life-spanning depreciation calculations are those accepted by the Commission at Docket No. R-00943271.

5. BOOK DEPRECIATION RESERVE

As indicated in prior retail rate filings, PP&L's book reserve is the proper depreciation reserve to use in determining the rate base for all plant. The book reserve was accepted for ratemaking purposes by the Commission at Docket No. R-842651.

6. SUSQUEHANNA MODIFIED SINKING FUND DEPRECIATION

Property installed at Susquehanna prior to January 1, 1989 was originally depreciated using a system of depreciation known as modified sinking fund (MSF). This method, which was approved by the Commission in its Final Order at Docket No. R-842651, subsequently was modified by the Commission, in its Final Order at Docket No. P-880332, to permit the Company to comply with the requirements of Statement of Financial Accounting Standards No. 92 ("SFAS 92"). In its Final Order at Docket No. R-00943271, the Commission approved the Company's request to levelize the remaining MSF annual depreciation amount through 1998, rather than maintaining the prior annual escalation of MSF depreciation expense. On January 1, 1999, the annual depreciation expense for Susquehanna property is scheduled to decrease from the levelized

MSF amount of approximately $173 million per year to a straight-line amount of approximately $105 million per year.

7. GENERAL PLANT AMORTIZATION

In its Final Order at Docket No. R-00943271, the Commission approved the Company's request to switch to amortization accounting for the following classes of assets: General Plant Accounts 391.2, 391.4, 391.6, 393.0, 394.0, 394.4, 394.6, 394.8, 395.0 and 398.0 and for similar equipment contained in the Miscellaneous Power Plant Equipment accounts.

8. DEPRECIATION RESERVE ADJUSTMENT

The Company is proposing to adjust its depreciation reserve detail books of account to reflect the results of various Commission-approved changes in depreciation life parameters.

Q. Please discuss the depreciation reserve adjustment that the Company is proposing.

A. Through December 31, 1988, the Company used the whole-life technique of depreciation. This technique simply applies a depreciation rate, known as a whole-life rate, to the existing balance of plant in service. An estimated, or theoretical, depreciation reserve can be calculated for this technique by applying calculated vintaged accrued depreciation rates to existing vintaged plant in service. Whenever approval is given by the Commission for a change in depreciable life or dispersion characteristics, the new depreciation parameters are used to calculate an entirely new theoretical depreciation reserve. The assumption is made that the new parameters have been in effect for the entire existence of the plant account being analyzed, although this is obviously not the case. A comparison of the resultant theoretical depreciation reserve to the book reserve reveals a newly created variance. This variance can be either positive or negative, depending on whether the depreciation parameters were extended or shortened.

Prior to filing its most recent retail base rate case at Docket No. R-00943271, the Company had not filed a base rate case with the PUC for over 10 years. The depreciation service life study filed in the prior base rate request was completed in 1981 using data ended December 31, 1980. In its most recent rate filing, the Company submitted an updated depreciation service life study that reflected service life or dispersion characteristic changes for virtually every plant account. Within the Transmission plant function, these changes generally produced a positive reserve variance when the calculated depreciation reserve was compared to the book reserve. That is, the calculated reserve exceeded the book reserve. Within the Distribution plant function, these changes generally produced a negative reserve variance when the calculated depreciation reserve was compared to the book reserve. That is, the calculated reserve was less than the book reserve. The net variance for both plant functions is approximately $204.8 million, with the calculated theoretical reserve being less than the book depreciation reserve.

Q. What is the Company's proposal regarding this depreciation reserve variance?

A. Because the Company currently uses the remaining life technique in its calculation of depreciation expense, these depreciation reserve variances would tend to be ameliorated over the remaining life of the property. However, in the context of this proceeding, the Company is proposing to make a one-time adjustment to the detailed depreciation reserve books of account. It is proposing to adjust the Transmission and Distribution depreciation reserves on its books of account to the level calculated as the theoretical depreciation reserve at December 31, 1998. It also is proposing to adjust the Nuclear Production depreciation reserve on its books of account by an equal amount. The net effect would be to increase net plant for the Distribution function, and to decrease net plant for both the Transmission and Nuclear Production functions.

Q. Why does the Company believe that this proposed adjustment is appropriate?

A. The Company believes this proposed adjustment is appropriate for the following three reasons. First, the proposed adjustments to the Transmission and Distribution depreciation reserves on the Company's books of account accurately reflect the theoretical depreciation reserve calculated at December 31, 1998 for these accounts. Second, the adjustment to the Nuclear Production depreciation reserve on the Company's books of account will enable the Company to reduce its stranded cost claim by more than $ 317 million, as discussed by Mr. Schadt in his direct testimony. Third, the Act specifically contemplates this type of depreciation reserve reallocation as a means of mitigating stranded costs. Finally, the proposal for an adjustment to the Nuclear Production depreciation reserve to offset the adjustments to the Transmission and Distribution depreciation reserves is consistent with the implementation of the rate cap established by the Act, and maintains the Company's retail charges at the level in effect on January 1, 1997.

Q. Does this conclude your statement of direct testimony?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKET NO. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

STATEMENT NO. 6

DIRECT TESTIMONY OF PAUL R. MOUL

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

A. My name is Paul Ronald Moul. My business address is Cherry Tree Corporate Center, 535 Route 38 East, Suite 200, Cherry Hill, New Jersey 08002. I am Managing Consultant of the firm P. Moul & Associates, Inc., an independent, financial and regulatory consulting firm. In my capacity as Managing Consultant and for over twenty years, I have provided cost of capital and fair rate of return testimony in numerous proceedings before the Pennsylvania Public Utility Commission ("PUC" or the "Commission") and before many other regulatory commissions at the federal and state level. I appeared as an expert witness on behalf of Pennsylvania Power & Light Company ("PP&L" or the "Company") in its most recent base rate case at Docket No. R-00943271.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return on common equity that the Commission should recognize in calculating the transition or stranded costs for PP&L. My testimony addresses two issues. First, what is the appropriate cost of equity for PP&L in the historic base year 1996? Second, is that cost of equity appropriate for calculating the Company's transition or stranded costs extending into the future, which may encompass costs which will be incurred for up to 30 years?

Q. What cost of equity have you determined for PP&L applicable to the 1996 historic base year?

A. My analysis indicates that the rate of return on common equity which should be used for the base year is at least 12.75%. I understand, however, that the Company has reflected an 11.5% rate of return on common equity in its filing with the Commission. The 11.5% rate of return on common equity is consistent with the Commission's Final Order in the Company's most recent base rate case at Docket No. R-00943271. Based upon my independent analysis, the 11.5% rate of return on common equity contained in the calculation of the transition or stranded costs is below the Company's actual cost of equity.

Q. What is your basis for the determination of the Company's cost of equity?

A. In arriving at my determination that the Company's cost of equity is at least 12.75%, I have relied on four, well-recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that my cost of equity is consistent with the well-recognized principles for determining a fair rate of return. The models which I used to measure the cost of equity for the Company have been applied with capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of equity, for an electric utility such as PP&L. In this regard, the models have been applied with market data taken from PP&L

Resources, Inc. ("PP&L Resources"), the parent company of PP&L, and a Barometer Group of Eight Electric Companies (the "Barometer Group"). The results of my study are contained in a report which accompanies my direct testimony and is identified as Exhibit PRM 1. The financial and market data supporting my report are identified as Exhibit PRM 2.

In general, the use of more than one approach provides a superior foundation to arrive at the cost of equity. At any point in time, individual methods can provide an incomplete measure of the cost of equity depending upon a variety of extraneous factors which may influence the way the market regards the stock. The following table provides a summary of the indicated costs of equity using each of these approaches.

	DCF	Risk Premium	CAPM	Comparable Earnings	Average of Four Methods	Midpoint of Range
PP&L Resources	11.09%	12.50%	12.44%	15.05%	12.77%	13.07%
Barometer Group	10.47%	12.50%	12.28%	15.05%	12.58%	12.76%

Using the PP&L Resources and Barometer Group data, the appropriate cost of equity is at least 12.75%. The rate of return on common equity that the Company should receive should be near the top of the range in recognition of its exemplary management performance. It is my opinion that an 11.5% rate of return on common equity, which is reflected in the Company's filing, is below that indicated by the market models. Moreover, it is my opinion that an 11.5% rate of return on common equity is the minimum necessary to support reasonable credit quality in light of the credit quality benchmarks established for electric utilities. I have provided a more detailed discussion of the credit quality implications of the Company's overall rate of return in Exhibit PRM 1. As a consequence, the Company must be provided an opportunity to experience a financial profile that fits those criteria and is commensurate with the business risks of the electric utility industry.

Q. In your opinion, does a determination of the cost of equity for the base year 1996 provide a reasonable basis to determine costs which may extend up to 30 years in the future?

A. The use of 1996 as a base period to establish a long-term rate of return on common equity is likely to result in an understatement of the cost of equity for the next 30 years. I say this because interest rates in 1996 were relatively low by recent historical standards. The level of interest rates in 1996 are shown together with historical interest rates on the graph presented in Exhibit PRM 3. On that exhibit, I have presented the monthly yields for Moody's index of A rated public utility bonds from January 1986 through December 1996. This graph shows that the 1996 data which the Commission will use in setting the transition or stranded costs for PP&L have been taken from a period of relatively low interest rates by historical standards. Essentially, the yield on public utility bonds at the beginning of 1996 was near the trough of interest rates which occurred in October 1993. Although interest rates rose from the beginning of 1996, the average yield for the year was 7.75% for A rated public utility bonds.

Q. What are the implications of relatively low interest rates regarding the Company's cost of equity for the future?

A. As I understand it, PP&L is utilizing 1996 capital cost data as a proxy for future capital costs in calculating its stranded cost recovery claim. It appears obvious that if interest rates rise from their current low levels, the cost of equity determined from 1996 data will understate the future cost of equity. Although it is always possible that interest rates could move lower, this possibility is outweighed 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 relatively low interest rates. Indeed, the average yield for Moody's index of A rated public utility bonds was 9.03% for the monthly yields from 1986 to 1996, shown on Exhibit PRM 3, when this average yield is compared to the average yield for 1996 of 7.75% noted above.

Q. What recommendations do you have for the Commission concerning the rate of return on common equity which should be reflected in the determination of the Company's transition or stranded cost recovery?

A. First, the 11.5% rate of return on common equity used for the base period 1996 in the Company's filing is low. My independent analysis indicates that a higher 12.75% cost of equity is indicated from the market evidence taken from the year 1996. Second, whatever rate of return on common equity is used for the base year 1996 will likely prove to be too low for the future because 1996 was a period of relatively low interest rates. PP&L's use of an 11.5% cost of equity in its analysis is clearly conservative and is at the low end of any range of reasonableness.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT PRM 1

PENNSYLVANIA POWER & LIGHT COMPANY

Determination of the Cost of Equity

Pennsylvania Power & Light Company ("PP&L" or the "Company") has engaged P. Moul & Associates, Inc., of Cherry Hill, N.J. to measure the Company's cost of equity for the determination of its transition or stranded cost recovery. The cost of equity was derived from the application of a variety of methods/models including: Discounted Cash Flow ("DCF") model, Risk Premium approach, Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings method. The resulting rate of return on common equity is represented by the average and range of the results of each of the models/methods. Detailed financial and market data in support of the rate of return on common equity is provided in Exhibit PRM 2. Schedule references throughout this report relate to data contained in Exhibit PRM 2.

The common stock shares of PP&L are not traded because the Company is a wholly-owned subsidiary of PP&L Resources, Inc. ("PP&L Resources"). PP&L Resources' stock is traded on the NYSE and regional exchanges and is a member of the S&P 500 Composite Index and S&P Public Utilities. In addition to data for PP&L Resources, a Barometer Group (i.e., proxy group) approach has also been used to measure the cost of equity with financial and market data derived from a group of eight electric companies. The selection criteria for the Barometer Group and identities of the component companies may be found on page 2 of Schedule 3. Prior to undertaking an analysis of the Company's cost of equity using PP&L Resources and the Barometer Group data, it is first necessary to assess the relative risk position of PP&L. From a risk assessment perspective, PP&L has been assigned an "Average" business position by Standard & Poor's Corporation ("S&P"), a major credit rating agency.

It is useful to enumerate the factors which impact the Company's business risk profile. A list of strengths as perceived by investors in PP&L include:

- Regionally competitive rates
- Winter-peaking utility in a summer-peaking region
- Strong capacity position
- High levels of generating station availability
- Aggressive marketing and economic development programs
- Emphasis on cost control, especially the size of the workforce, and the refinancing of high cost debt and preferred stock
- Initiatives to strengthen its position in the wholesale markets through marketing of capacity and energy

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

- The relatively large concentration of assets in the Susquehanna station
- Nuclear decommissioning costs
- Coal mine closure costs, including miners' health care costs
- Relatively high cost of energy obtained from NUGs
- Potential CAAA compliance in Phase II
- Other environmental issues

The Company's financial condition was compared to that of the Barometer Group and the S&P Public Utilities (an industry-wide group identified on pages 3 and 4 of Schedule 4). The financial data for the fundamental risk analysis may be found on Schedules 2, 3 and 4. An objective assessment of these data would indicate that the Barometer Group has somewhat lower risk than PP&L Resources, and thus its market evidence would understate the Company's cost of equity. Higher risk traits for the Company vis-a-vis Barometer Group would include: the Company has a somewhat lower bond rating (i.e., A- for PP&L compared with A for the Barometer Group), the Company has higher financial risk (i.e., a 42.3% common equity ratio for PP&L Resources compared to 44.7% common equity ratio for the Barometer Group), the Company has more variable earned returns (i.e., a coefficient of variation of 0.156 for PP&L Resources compared to 0.018 for the Barometer Group), and the Company has somewhat higher systematic risk (i.e., .77 beta for PP&L Resources compared to .72 beta for the Barometer Group).

Highlights of the methods employed to measure the cost of equity with PP&L Resources and the Barometer Group data follows:

Discounted Cash Flow (*"DCF"*) provides a familiar measure of the cost of equity for PP&L Resources and the Barometer Group. The DCF return (i.e., *"k"*) is the sum of the adjusted dividend yield (i.e., "D_1/P_0") and the growth rate (i.e., *"g"*). The resulting DCF cost rate is:

	D_1/P_0		g	=	k
PP&L Resources	7.59%	+	3.50%	=	11.09%
Barometer Group	6.97%	+	3.50%	=	10.47%

The DCF result shown above represents the simplified form of the model which contains a constant growth assumption.

Although the DCF model contains a variety of restrictive assumptions which severely limit its usefulness in the ratesetting context, the model has been employed with data for PP&L Resources and the Barometer Group using a dividend yield of 7.40% and

6.80%, respectively, based upon consideration of the 12-month average (i.e., 7.24% for PP&L Resources and 6.74% for the Barometer Group), 6-month average (7.44% for PP&L Resources and 6.81% for the Barometer Group), and 3-month average (7.31% for PP&L Resources and 6.75% for the Barometer Group) dividend yields shown on Schedule 5 pages 1 and 2. The dividend yields shown on that schedule reflect an ex-dividend adjustment. While the 7.40% and 6.80% dividend yields are not intended to represent a specific historical average, they are similar to the six-month averages. Using three different but generally acceptable formulas, the 7.40% and 6.80% dividend yields have been positioned in a forward-looking manner to arrive at the 7.59% adjusted dividend yield for PP&L Resources and 6.97% adjusted dividend yield for the Barometer Group.

The growth component for PP&L Resources and the Barometer Group consists of 3.00% growth attributed to company-specific factors and 0.50% attributed to market-wide factors. The support for the company-specific growth rates may be found on Schedules 6 and 7. The elements considered were growth in earnings per share, dividend per share, book value per share, cash flow per share, and internal growth for PP&L Resources and the Barometer Group using historical and projected data typically considered by investors. While some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their current dividend yield requirements.

To the company-specific growth rate of 3.00%, market-wide factors add 0.50% to the growth rate. Market-wide factors would include overall business conditions, monetary policy, fiscal and tax policy, the value of the dollar in foreign exchange, the balance of trade, all of which would comprise qualitative influences on investors' total return expectations. Qualitative factors must be considered because the fundamental analysis employed in reaching a growth rate forecast -- see Schedules 6 and 7 -- will not fully account for all market-wide factors because the quantitative growth analysis is company-specific. It is also not known to what extent securities' analysts incorporate market-wide factors into their estimates, or that analysts do this uniformly. In addition, as the electric industry adjusts to the new business environment, additional opportunities and risk will surely develop beyond the five-year horizon typically considered by the analysts' forecasts. The combination of both quantitative factors, as shown by company-specific variables, and qualitative factors, as shown by general investor sentiment, together form the foundation for the capital appreciation (i.e., capital gains yield) that investors expect from owning a common stock.

As noted above, there are a wide variety of factors that influence investor expected returns which are not linked to company-specific performance. In an article in Standard & Poor's The Outlook (February 21, 1996), the relative valuation of common stocks was explained in part by qualitative factors (i.e., favorable psychology). Recognition of market-wide factors is needed to synchronize the growth rate in the DCF with the stock price which includes both company-specific factors and general market sentiment which includes relative P/Es, dividend yields, interest rates, the supply of stocks, etc. Therefore, for the purpose of this case, a modest 0.5% growth rate for market-wide factors has been added to the growth rate shown by company-specific variables. By considering both company-specific and market-wide factors, a 3.50% growth rate is warranted for PP&L Resources and the Barometer Group. Recognition of market-wide qualitative factors represents a reasonable adjustment to the DCF growth rate. It has been demonstrated by the Goldman Sachs study that 38% of the rise in stock prices in the 1980s occurred due to unknown factors. As to the proposition that such qualitative factors are already reflected in stock prices under the efficient market hypothesis, it is the need to synchronize the growth rate employed in the DCF with the growth rate reflected in stock prices that necessitates recognition of qualitative factors. That is to say, while stock prices may reflect all information concerning both market-related and company-specific factors, the analysts' forecasts represent only company-specific growth. To make the DCF model at all useful, the growth rate component combined with the dividend yield must provide a result that conforms with the mix of current returns from dividends and long-term returns from capital gains.

Risk Premium approach is determined by a corporate bond yield -- here defined as the interest rate on A rated public utility bonds -- plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The cost rate of common equity (i.e., *"k"*) is represented by the sum of the long-term public utility debt yield (i.e., *"i"*) and the equity risk premium (i.e., *"RP"*). The Risk Premium approach provides a cost of equity of:

$$\begin{array}{ccccc} i & + & RP & = & k \\ 7.75\% & + & 4.75\% & = & 12.50\% \end{array}$$

The interest rate component of the Risk Premium approach is 7.75% based upon historical yields on A rated public utility bonds -- see Schedule 8 -- and forecasts published by Blue Chip Financial Forecasts. Forecast yields for A rated public utility long-term debt (according to the January 1, 1997 Blue Chip Financial Forecast) are as follows:

Quarter	Yield
1st Qtr. 1997	7.6%
2nd Qtr. 1997	7.6
3rd Qtr. 1997	7.6
4th Qtr. 1997	7.5
1st Qtr. 1998	7.6
2nd Qtr. 1998	7.6

The average analysts' projection for the second quarter of 1998 is bounded by an 8.3% average of the highest ten estimates and a 7.0% average of the lowest ten estimates. Given these forecasts and the historical long-term interest rates, a 7.75% yield on A rated public utility bonds is reasonable.

Schedule 9 provides the financial returns that were used to develop the appropriate equity risk premium for the S&P Public Utilities, from which the equity risk premium for PP&L Resources and the Barometer Group was determined. To develop an appropriate risk premium, the results were analyzed for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. As shown by the values indicated on page 2 of Schedule 9, the indicated risk premiums for the various time periods analyzed are 5.28% (1928-1996), 6.15% (1952-1996), 5.28% (1974-1996), and 5.55% (1979-1996). The selection of the shorter periods taken from the entire historical series was designed to provide a risk premium which conforms more nearly with present investment fundamentals and removes some of the more distant data from the analysis. Using the summary values provided on page 2 of Schedule 9, the 1928-1996 and 1974-1996 periods provided the lowest indicated risk premium, while the 1952-1996 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.42% (5.28% + 5.55% = 10.83% ÷ 2) is shown from data covering the periods 1974-1996 and 1979-1996 which represents the more recent results. Based upon various measures of risk differentials among PP&L Resources, the Barometer Group and the S&P Public Utilities including size, market ratios, common equity ratio, return on book equity, operating ratios, coverages, quality of earnings, internally generated funds, and betas (see Schedules 2, 3, and 4), these differences indicate that 4.75% represents a reasonable common equity risk premium in this case. This represents 88% (4.75% ÷ 5.42%) of the risk premium of the S&P Public Utilities and is reflective of the risk of PP&L Resources and the Barometer Group compared with that of the S&P Public Utilities.

Capital Asset Pricing Model ("CAPM") cost of equity is represented by a yield on a risk-free interest bearing obligation plus a return representing a premium which is proportional to the systematic risk of an investment. In contrast to the Risk Premium approach which considers industry and company-specific factors, the CAPM reflects just systematic risk as measured by a stock's beta -- the risk associated with changes in the overall market for common equities. Two forms of the CAPM have been employed -- the traditional Sharpe-Lintner model and a zero-beta form of the model. The components used to implement the traditional CAPM are shown on Schedule 10: page 1 for the beta, pages 2, 3 and 4 for the risk-free rate of return, and pages 5, 6 and 7 for the market premiums. From both the historical and forecast data, a risk-free rate of return of 6.75% for 30-year Treasury bonds is reasonable for CAPM purposes. The calculation of the market premium is developed from both historical market performance (i.e., 12.7% - 5.4% = 7.3%) and by the Value Line and S&P forecasts (i.e., 13.48% - 6.75% = 6.73%). The resulting market premium is 7.02% (7.3% + 6.73% = 14.03% ¸ 2) which represents the average market premium using the historical SBBI data and the Value Line forecasts. Using the 6.75% risk-free rate of return, the average beta of .76 for PP&L Resources and .73 for the Barometer Group, and the appropriate market premium, the following CAPM results are indicated:

	Rf	+	*b*	*(Rm-Rf)*	=	*k*
PP&L Resources	6.75%	+	.76	(7.02%)	=	12.09%
Barometer Group	6.75%	+	.73	(7.02%)	=	11.87%

To develop a return on a portfolio with a zero-beta (*"Rz"*), one-half of the market premium was assigned to the intermediate term Treasury note yield -- the Treasury note yield being 0.25% less than the yield on 30-year Treasury bonds. Here, the *Rz* is 10.07% (6.50% + 3.57%). The market premium which provides the basis for the return on the zero-beta portfolio was calculated in a manner similar to that described for the traditional CAPM above. Here, the forecast market premium (13.48% - 6.50% = 6.98%) was developed from the Value Line and S&P projections and was combined with the historical results taken from the SBBI data series (i.e., 12.7% - 5.4% = 7.3%) to produce an average 7.14% (6.98% + 7.3% = 14.28% ¸ 2) market premium. One-half of the market premium (7.14% ¸ 2 = 3.57%) was then assigned to the zero-beta portfolio and the remaining 3.57% was adjusted for the systematic risk of PP&L Resources and Barometer Group. Using the 10.07% return on a zero-beta portfolio, the average beta of .76 for PP&L Resources and .73 for the Barometer Group, and the appropriate market premium, the following results are indicated.

	Rf	+	b	(Rm-Rf)	=	k
PP&L Resources	10.07%	+	.76	(3.57%)	=	12.78%
Barometer Group	10.07%	+	.73	(3.57%)	=	12.68%

The average CAPM result is 12.44% (12.09% + 12.78% = 24.87% ÷ 2) for PP&L Resources and the average CAPM result is 12.28% (11.87% + 12.68% = 24.55% ÷ 2) for the Barometer Group.

Comparable Earnings approach has been used extensively in rate of return analysis for over a half century. The Comparable Earnings approach has been implemented in this case with data taken from thirteen (13) non-regulated companies using six criteria from the Value Screen Data Base to establish comparability as set forth on page 1 of Schedule 11. Based upon an average of historical and forecast rates of return on book common equity, the Comparable Earnings result is supported by the data provided on page 2 of Schedule 11. That average is 15.05% (15.4% + 14.7% = 30.1% ÷ 2) for the Comparable Earnings group. The Comparable Earnings result was verified by use of a market-determined cost of equity for the same Comparable Earnings companies as set forth on page 3 of Schedule 11. The Comparable Earnings approach is consistent with the Company's move from cost-of-service ratesetting to competitive markets. As such, the Company's risk will increase in the future and the ratesetting process should emulate the returns achieved by non-regulated firms operating in a competitive market. This makes the Comparable Earnings approach relevant to a measurement of the Company's cost of equity.

Credit Quality issues also play a critical role in the determination of the Company's rate of return on common equity. It is necessary to verify the reasonableness of the overall rate of return which must include a reasonable cost of equity by reference to the benchmarks of credit quality in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. It is important that the Company is provided with a reasonable opportunity to achieve adequate credit quality so that its financial condition is commensurate with its public service obligation. In this regard, coverage of the Company's senior capital costs reveals the level of protection that PP&L can supply for its fixed obligations. Interest coverage is measured on both a before- and after-income tax basis. Normally, before-income tax coverage is used for the purpose of a company's debt interest coverage and overall after-income tax coverage is the measure employed with regard to interest charges and preferred stock dividends.

It is important to re-emphasize that public utilities must compete in the capital markets to attract needed future dollars and, as such, interest coverage should be used as a test to measure the adequacy of the rate of return. Of course, it is not the only factor to be considered in testing the appropriate rate of return and must be viewed in relation to an individual company's degree of financial leverage and cash flow benchmarks. Maintenance of a strong A bond rating financial profile is the appropriate regulatory objective and an AA bond rating should be encouraged. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Using a 41.4935% statutory federal and state income tax rate, the pre-tax coverage of interest expense would be 3.65 times assuming the Company could actually realize an 11.5% rate of return on common equity in the context of the December 31, 1996 capital structure. This pre-tax interest coverage is shown on Schedule 1, together with post-tax coverage of interest expense and overall coverage of interest and preferred stock dividends.

The pre-tax interest coverage and debt leverage shown on Schedule 1 should be viewed in the context of the S&P bond rating criteria which specifies 3.50 times pre-tax interest coverage and a 47% debt ratio for an A bond rating for an electric utility with an average business position. It is important to recognize that the benchmarks represent levels expected to be achieved. With these credit quality benchmarks, the Company needs to achieve at a minimum the credit quality profile reflective of the financial conditions shown on Schedule 1. The Commission should encourage higher levels of interest coverage in the context of higher credit quality standards for the electric utilities in an increasingly competitive electric utility industry.

EXHIBIT PRM 2

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit to Accompany

the Direct Testimony

of

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

Concerning

Fair Rate of Return

PENNSYLVANIA POWER & LIGHT COMPANY

Index of Schedule

Exhibit
Schedule 1

Pennsylvania Power & Light Company
Rate of Return Calculation
Actual at December 31, 1996

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.01%	7.89%	3.71%
Preferred Stock	7.79%	7.10%	0.55%
Common Equity	45.20%	11.50%	5.20%
Overall Cost of Capital	100.00%		9.46%

Indicated level of fixed coverage assuming the Company could actually achieve a 9.46% overall rate of return.

Before-income tax coverage of interest expense based upon a 41.4935% effective federal and state income tax rate. (13.54% / 3.71%)	3.65x
After-income tax coverage of interest expense (9.46% / 3.71%)	2.55x
Overall coverage of interest expense and preferred stock dividends (9.46% / 4.26%)	2.22x

PP&L Resources
Capitalization and Financial Statistics
1991-1995, Inclusive

	1995	1994	1993	1992	1991	
		(Thousands of Dollars)				
Amount of Capital Employed						
Total Permanent Capital (incl.cap.leases)	$6,141,853	$6,086,397	$5,843,805	$5,794,368	$5,748,184	
Short-Term Debt	89,145	74,168	202,260	159,348	147,170	
Total-Capital Employed	$6,230,998	$6,160,565	$6,046,065	$5,953,716	$5,895,354	
Indicated Average Capital Cost Rates (1)						
Long Term Debt	6.8%	7.1%	7.8%	8.4%	8.2%	
Financial Ratios-Market Based						5 Year Average
Earnings/Price Ratio	9.2%	6.1%	7.2%	7.8%	8.5%	7.8%
Market/Average Book	138.3%	144.6%	181.2%	169.6%	158.1%	158.4%
Dividend Yield	7.5%	7.3%	5.8%	6.1%	6.6%	6.7%
Dividend Payout Ratio	81.7%	118.8%	79.8%	79.2%	77.2%	87.3%
Capital Structure Ratios						
Based on Total Permanent Captial:						
Long-Term Debt	50.1%	52.0%	49.8%	49.7%	49.6%	50.2%
Preferred Stock	7.6%	7.7%	8.7%	9.5%	10.4%	8.8%
Common Equity	42.3%	40.3%	41.5%	40.8%	40.0%	41.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	50.8%	52.6%	51.5%	51.0%	50.9%	51.3%
Preferred Stock	7.5%	7.6%	8.4%	9.2%	10.1%	8.6%
Common Equity	41.7%	39.8%	40.1%	39.8%	39.0%	40.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	12.8%	8.8%	13.1%	13.1%	13.4%	12.2%
Operating Ratios (2)	69.6%	73.6%	70.7%	70.8%	68.8%	70.7%
Coverages-Including All AFC (3)						
Before Income Taxes: All Interest Charges	3.6 x	2.8 x	3.4 x	3.3 x	3.2 x	3.3 x
After Income Taxes: All Interest Charges	2.4	2.0	2.4	2.4	2.4	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	1.8	2.1	2.0	2.0	2.0
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.5 x	2.8 x	3.4 x	3.2 x	3.2 x	3.2 x
After Income Taxes: All Interest Charges	2.3	2.0	2.4	2.3	2.3	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	1.8	2.1	2.0	2.0	2.0
Quality of Earnings						
AFC/Income Available for Common Equity	3.7%	6.1%	5.0%	4.9%	3.9%	4.7%
Effective Income Tax Rate	46.9	42.4	40.2	39.7	38.3	41.5
Internal Cash Generation/Gross Construction (4)	97.1	91.9	88.9	108.0	137.6	104.7
Gross Cash Flow/ Permanent Captial (5)	10.9	12.1	12.1	12.5	13.5	12.2
Gross Cash Flow/ Avg. Total Debt(6)	20.9	23.2	22.9	23.9	25.8	23.3
Gross Cash Flow Interest Coverage(7)	3.9 x	4.1 x	3.9 x	3.9 x	4.1 x	4.0 x
Common Dividend Coverage (8)	2.4	2.8	2.7	2.8	3.1	2.8

See Page 2 for Notes.

PP&L Resouces, Inc.
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

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

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

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

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

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

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

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

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

	Bond Rating		Common Stock Traded	S&P Common Stock Ranking	Market Sensitivity Statistics		Business Position
	Moody's	S&P			Beta	R^2	
PP&L Resources, Inc.	A2	A-	NYSE	A-	0.77	0.09	Average

Source of Information: OneSource
Standard & Poor's Utility Compustat
Moody's Public Utilities Manual and Bond Survey
S&P Bond Guide and Creditweek
S&P Stock Guide
Merrill Lynch Security Risk Evaluation, January 1997

Barometer Group of Eight Electric Companies
Capitalization and Financial Statistics (1)
1991-1995, Inclusive

	1995	1994	1993	1992	1991	5 Year Average
			(Thousands of Dollars)			
Amount of Capital Employed						
Total Permanent Capital	$5,501,810	$5,516,467	$5,314,474	$5,182,525	$4,998,591	
Short-Term Debt	303,305	176,721	184,327	152,307	200,394	
Total Capital Employed	$5,805,115	$5,693,188	$5,498,800	$5,334,832	$5,198,985	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	6.6%	6.7%	7.2%	7.4%	7.6%	
Financial Ratios-Market Based						
Earnings/Price Ratio	7.5%	8.3%	7.2%	7.5%	8.4%	7.8%
Market/Average Book	147.0%	140.7%	162.6%	149.8%	135.8%	147.2%
Dividend Yield	6.9%	7.2%	6.3%	6.9%	7.6%	7.0%
Dividend Payout Ratio	104.8%	88.1%	89.6%	91.3%	91.3%	93.0%
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	49.2%	48.7%	48.3%	48.5%	49.4%	48.8%
Preferred Stock	6.1%	7.0%	7.6%	8.0%	7.7%	7.3%
Common Equity	44.7%	44.4%	44.2%	43.5%	42.9%	43.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	51.5%	49.9%	49.6%	50.0%	51.1%	50.4%
Preferred Stock	5.8%	6.8%	7.4%	7.8%	7.4%	7.1%
Common Equity	42.7%	43.3%	43.0%	42.2%	41.4%	42.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	10.9%	11.5%	11.5%	11.3%	11.4%	11.3%
Operating Ratios (3)	76.0%	76.4%	76.4%	78.2%	78.0%	77.0%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	3.1 x	3.3 x	3.1 x	3.0 x	2.9 x	3.1 x
After Income Taxes: All Interest Charges	2.3	2.5	2.4	2.3	2.3	2.4
Overall Coverage: All Interest + Pfd. Div.	2.1	2.2	2.1	2.0	2.0	2.1
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.1 x	3.2 x	3.0 x	2.9 x	2.7 x	3.0 x
After Income Taxes: All Interest Charges	2.3	2.4	2.3	2.2	2.1	2.3
Overall Coverage: All Interest + Pfd. Div.	2.0	2.1	2.0	1.9	1.9	2.0
Quality of Earnings						
AFC/Income Available for Common Equity	5.1%	7.1%	7.0%	8.0%	12.5%	7.9%
Effective Income Tax Rate	35.8	33.4	33.4	32.6	31.8	33.4
Internal Cash Generation/Gross Construction (4)	113.1	84.9	87.8	71.9	56.6	78.8
Gross Cash Flow/ Permanent Capital (5)	11.3	10.7	10.0	9.8	9.6	10.3
Gross Cash Flow/ Avg. Total Debt(7)	22.2	21.6	20.3	19.5	18.7	20.5
Gross Cash Flow Interest Coverage(8)	4.0 x	4.0 x	3.7 x	3.6 x	3.4 x	3.7 x
Common Dividend Coverage (9)	2.5	2.3	2.2	2.1	2.1	2.2

See Page 2 for Notes.

Barometer Group of Eight Electric Companies
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

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

Basis of Selection:

The criteria used in the selection of this barometer group of Electric Companies were to include those companies that are included in Standard & Poor's Utility Compustat II, have SIC Code, 4911 (Electric Services) and 4931 (Electric and other services combined), common stock which is traded on the NYSE, operate in Pennsylvania or the six contiguous states to it, have not cut or omitted their dividends, have 1995 operating revenues above $750 million.

	Bond Rating		Common Stock	S&P Common Stock	Market Sensitivity Statistics		Business
	Moody's	S&P	Traded	Ranking	Beta	R^2	Position
Allegheny Power System(1)	Aa3	A+	NYSE	A-	0.71	0.10	High Average
American Electric Power Co.(2)	Baa1	BBB+	NYSE	B+	0.70	0.07	Somewhat Above Avg.
Atlantic Energy, Inc.(3)	A3	A-	NYSE	A-	0.65	0.04	Low Average
Baltimore Gas & Electric Co.	A1	A+	NYSE	A	0.85	0.20	Average
Delmarva Power & Light Co.	A2	A	NYSE	B+	0.58	0.04	Average
DPL, Inc.(4)	A1	AA-	NYSE	A-	0.60	0.07	High Average
Potomac Electric Power Co.	A1	A	NYSE	B	0.81	0.12	Somewhat Above Avg.
Public Service Enterprise Group (5)	A2	A-	NYSE	B+	0.87	0.21	Somewhat Below Avg.
	A2	A		A-	0.72	0.11	Average

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

Source of Information: OneSource;
Standard & Poor's Utility Compustat II
Moody's Public Utility Manual and Bond Surveys
S&P Bond Guides, CreditWeek
S&P Stock Guides
Merrill Lynch Security Risk Evaluation, January 1997

Standard & Poor's Utility Index
Capitalization and Financial Statistics(1)
1991-1995, Inclusive

	1995	1994	1993	1992	1991	5 Year Average
Amount of Capital Employed						
Total Permanent Capital	$8,234,409	$8,186,018	$8,193,131	$8,283,170	$8,287,889	
Short-Term Debt	413,347	441,852	471,132	376,505	368,474	
Total Capital Employed	$8,647,757	$8,627,870	$8,664,263	$8,659,674	$8,656,363	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	4.0%	4.6%	5.5%	5.5%	5.8%	
Financial Ratios-Market Based						
Earnings/Price Ratio	6.7%	6.9%	4.7%	7.1%	6.0%	6.3%
Market/Average Book	236.6%	200.8%	215.6%	180.4%	170.2%	200.7%
Dividend Yield	4.8%	5.5%	4.9%	5.7%	5.9%	5.4%
Dividend Payout Ratio	68.8%	77.6%	99.3%	78.4%	93.2%	83.5%
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	50.2%	48.5%	48.2%	49.1%	49.7%	49.1%
Preferred Stock	4.6%	4.6%	4.4%	4.4%	4.4%	4.5%
Common Equity	45.2%	46.9%	47.4%	46.5%	45.9%	46.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, Including Short Term	52.6%	51.2%	51.0%	51.3%	51.9%	51.6%
Preferred Stock	4.4%	4.3%	4.2%	4.2%	4.2%	4.3%
Common Equity	43.0%	44.5%	44.8%	44.5%	43.9%	44.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Average Book Common Equity	14.5%	13.7%	10.4%	12.9%	10.7%	12.4%
Operating Ratios (3)	83.8%	84.7%	86.5%	84.1%	84.9%	84.8%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	3.4 x	3.5 x	2.8 x	3.0 x	2.5 x	3.0 x
After Income Taxes: All Interest Charges	2.5	2.6	2.1	2.3	2.0	2.3
Overall Coverage: All Interest + Pfd. Div.	2.3	2.4	2.0	2.2	1.9	2.2
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.4 x	3.4 x	2.7 x	3.0 x	2.5 x	3.0 x
After Income Taxes: All Interest Charges	2.5	2.5	2.1	2.3	1.9	2.3
Overall Coverage: All Interest + Pfd. Div.	2.3	2.4	2.0	2.1	1.8	2.1
Quality of Earnings						
AFC/Income Available for Common Equity	2.7 %	2.9 %	5.6 %	4.6 %	6.9 %	4.5 %
Effective Income Tax Rate	37.8	36.2	36.5	34.5	34.6	35.9
Internal Cash Generation/Gross Construction (5)	113.7	100.7	104.9	95.5	91.7	101.3
Gross Cash Flow/ Permanent Capital (6)	16.1	16.2	16.5	15.0	14.4	15.6
Gross Cash Flow/ Avg. Total Debt(7)	29.6	30.0	30.4	27.7	27.0	28.9
Gross Cash Flow Interest Coverage(8)	4.6 x	4.9 x	4.8 x	4.3 x	4.0 x	4.5 x
Common Dividend Coverage (9)	3.5	3.2	3.3	3.1	3.1	3.2

See Page 2 for Notes.

Standard & Poor's Utility Index
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the aggregated result of the 48 companies in the group.
(2) Computed by relating actual long-term debt interest booked to average of beginning and ending long-term debt reported to be outstanding.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of capital additions to utility plant, provided by internally-generated funds from operations, excluding all AFC, and after payment of all cash dividends divided by gross contribution expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFC) as a percent of preference and common equity).
(7) Gross Cash Flow (as defined in Note 6) as a percentage of average total debt.
(8) Gross Cash Flow (as defined in Note 6) plus interest charges, divided by interest charges.
(9) Common dividend coverage is the relationship of internally-generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

Source of Information: Standard & Poor's
Compustat Customer Business Unit

Standard & Poor's Utility Index
Capitalization and Financial Statistics
December 31, 1995

	Bond Rating Moody's	Bond Rating S&P	Common Stock Traded	S&P Common Stock Ranking	Market Sensitivity Statistics Adjusted Beta	Market Sensitivity Statistics R^2
Electric Utilities						
American Electric Power Co., Inc. (1)	Baa1	BBB+	NYSE	B+	0.70	0.07
Baltimore Gas & Electric Company	A1	A+	NYSE	A	0.85	0.20
Carolina Power & Light Company	A2	A	NYSE	A-	0.85	0.15
Central & South West Corp. (1)	Aa3	AA-	NYSE	A-	0.77	0.13
CINergy Corporation (1)	Baa2	A-	NYSE	B	0.85	0.24
Consolidated Edison Co.	Aa3	A+	NYSE	A	0.73	0.07
DTE Energy Company	Baa1	BBB+	NYSE	B+	0.87	0.19
Dominion Resources, Inc. (1)	A1	A	NYSE	A-	0.61	0.07
Duke Power Company	Aa2	AA-	NYSE	A-	0.63	0.07
Edison International (1)	Aa2	A+	NYSE	B+	1.08	0.18
Entergy Corp. (1)	Baa3	BBB	NYSE	B	0.90	0.14
FPL Group, Inc. (1)	A2	AA-	NYSE	B	0.59	0.04
General Public Utilities	Baa1	BBB+	NYSE	B	0.80	0.15
Houston Industries, Inc. (1)	A2	A	NYSE	B+	0.76	0.09
Niagara Mohawk Power Corp.	Baa3	BB-	NYSE	B	0.70	0.02
Northern States Power Company (2)	Aa2	AA	NYSE	A-	0.74	0.18
Ohio Edison Company (2)	Baa2	BBB-	NYSE	B	0.81	0.15
Pacific Gas & Electric Company	A2	A	NYSE	B	1.08	0.24
Pacificorp (2)	A2	A	NYSE	B+	0.62	0.05
PECO Energy Company (1)	Baa1	BBB+	NYSE	B	0.80	0.13
PP&L Resources	A2	A-	NYSE	A-	0.77	0.09
Public Service Enterprise Group (1)	A2	A-	NYSE	B+	0.87	0.21
Southern Company (1)	A2	A+	NYSE	A-	0.69	0.08
Texas Utilities Company (1)	Baa2	BBB+	NYSE	B+	0.53	0.01
Unicom Corporation (1)	Baa2	BBB	NYSE	B	1.04	0.17
Union Electric (2)	A1	AA-	NYSE	A-	0.82	0.20
Average	A2	A		A-	0.79	0.13

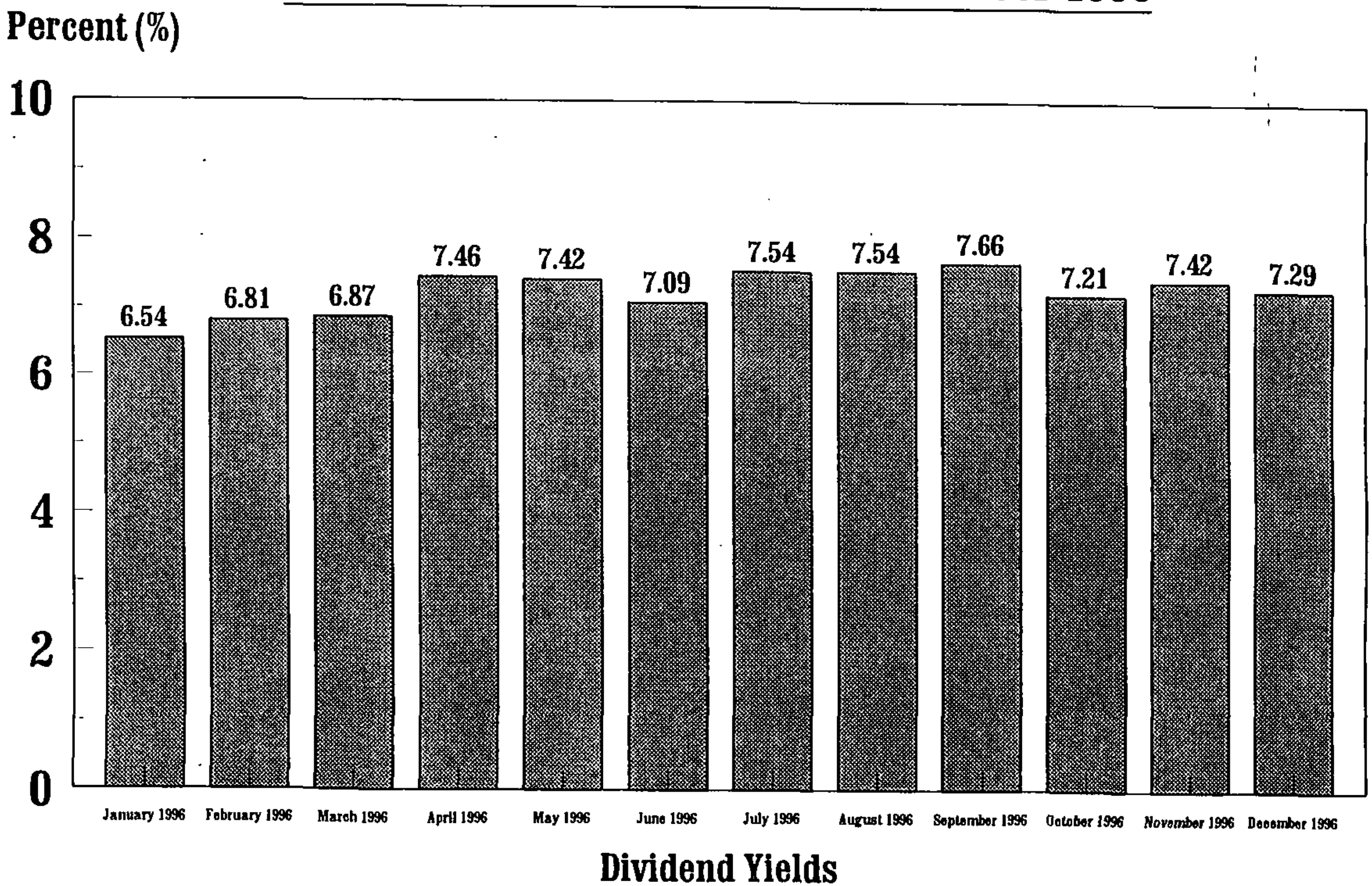
Standard & Poor's Utility Index
Capitalization and Financial Statistics
December 31, 1995

	Bond Rating Moody's	Bond Rating S&P	Common Stock Traded	S&P Common Stock Ranking	Market Sensitivity Statistics Adjusted Beta	Market Sensitivity Statistics R^2
Natural Gas Utilities						
Coastal Corporation (2)	Baa2	BBB-	NYSE	B+	1.22	0.29
Columbia Gas System, Inc.	Baa3	BBB	NYSE	NR	0.94	0.09
Consolidated Natural Gas Co.	A1	AA-	NYSE	B+	0.98	0.18
Eastern Enterprises (1)	A3	A	NYSE	B+	0.70	0.06
Enron Corporation (3)	Baa2	BBB+	NYSE	B+	0.85	0.07
ENSERCH Corporation	Baa2	BBB	NYSE	B	1.47	0.20
NICOR, Inc. (1)	Aa1	AA	NYSE	B+	0.82	0.14
NorAm Energy Corp. (2)	Ba2	BB+	NYSE	B	1.22	0.10
ONEOK, Inc.	Baa1	A-	NYSE	B	0.45	0.01
Pacific Enterprises (1)	A2	AA-	NYSE	B-	0.72	0.04
Pan Energy (1)	Baa3	BBB	NYSE	B	1.33	0.25
Peoples Energy Corp. (1)	Aa3	AA-	NYSE	B+	1.16	0.27
Sonat, Inc. (1)	Baa1	A-	NYSE	B	0.97	0.09
Williams Company	Baa3	BBB-	NYSE	B+	1.07	0.18
Average	Baa1	BBB+		B+	1.00	0.14
Telecommunications Companies						
Alltel Corporation (3)	A1	A+	NYSE	A	0.64	0.03
Ameritech Corp. (1)	Aa	AAA	NYSE	A-	0.97	0.21
Bell Atlantic Corporation (1)	Aa2	AA+	NYSE	A-	0.81	0.15
BellSouth Corporation (1)	Aaa	AAA	NYSE	B+	0.69	0.05
GTE Corporation (1)	A1	A+	NYSE	B+	0.69	0.05
NYNEX Corporation (1)	Aa3	A	NYSE	B+	0.83	0.15
Pacific Telesis Group (1)	Aa3	AA-	NYSE	B+	0.98	0.08
SBC Communications, Inc.	A1	A+	NYSE	A	0.72	0.09
US WEST, Inc. (1)	Aa3	AA-	NYSE	B+	0.51	0.01
Average	Aa3	AA-		B+	0.78	0.14
Average for S&P Utilities	A2	A		B+	0.85	0.13
Indexes:						
S&P Public Utilities					0.81	0.29
S&P Industrials					1.01	0.96
S&P Composite					1.00	1.00

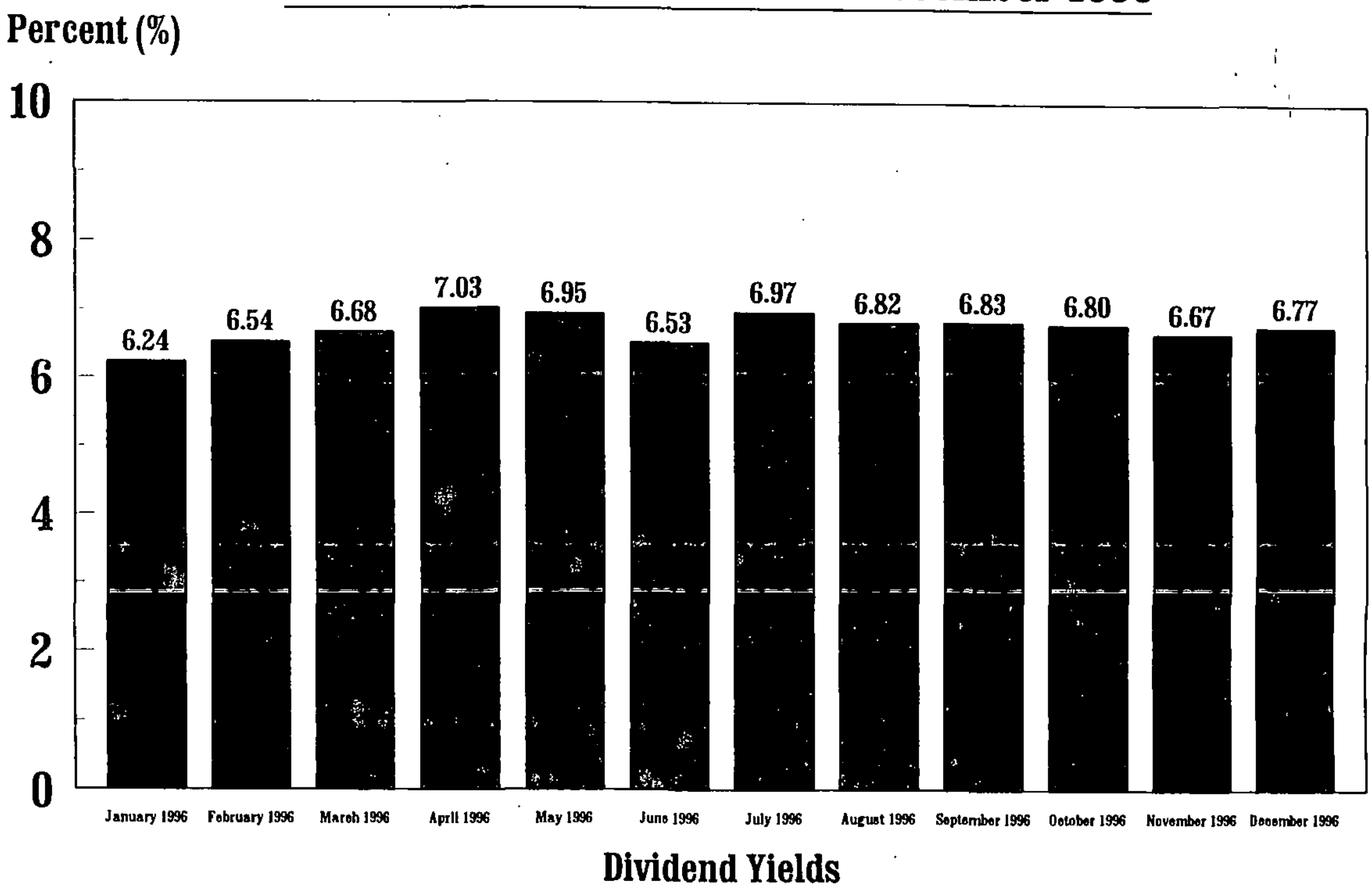
Notes:
(1) Composite rating for subsidiaries of holding companies.
(2) Composite rating for parent company as well as subsidiaries.
(3) Parent Company rating.

Source of Information: Moody's Public Utility Manual and Bond Survey
Standard & Poor's Stock and Bond Guide
Merrill Lynch Security Risk Evaluation, January 1997

PP & L Resources, Inc.
Monthly Dividend Yields
for the Twelve Months Ended December 1996



Barometer Group of Eight Electric Companies
Monthly Dividend Yields
for the Twelve Months Ended December 1996



Exhibit
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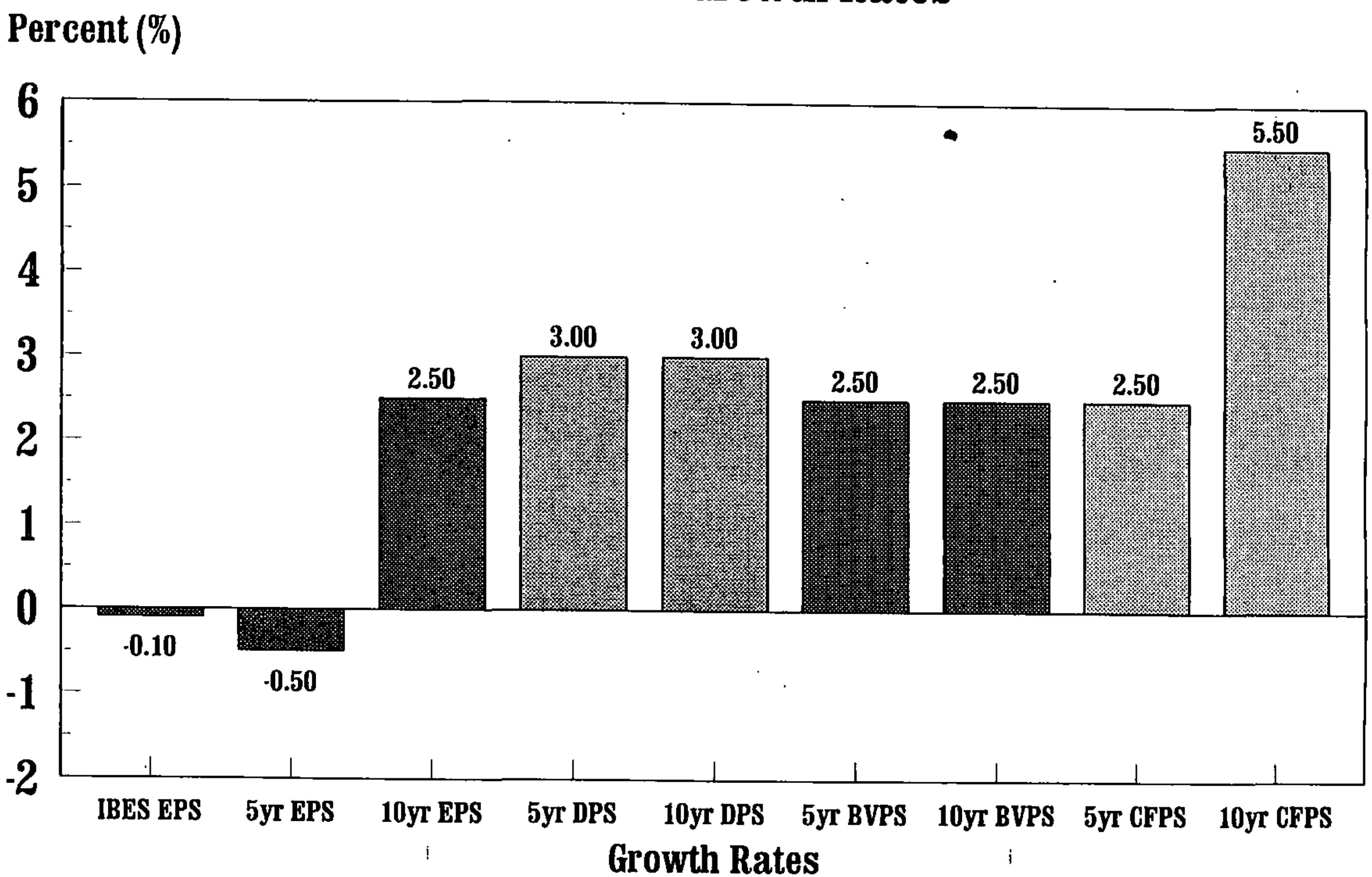
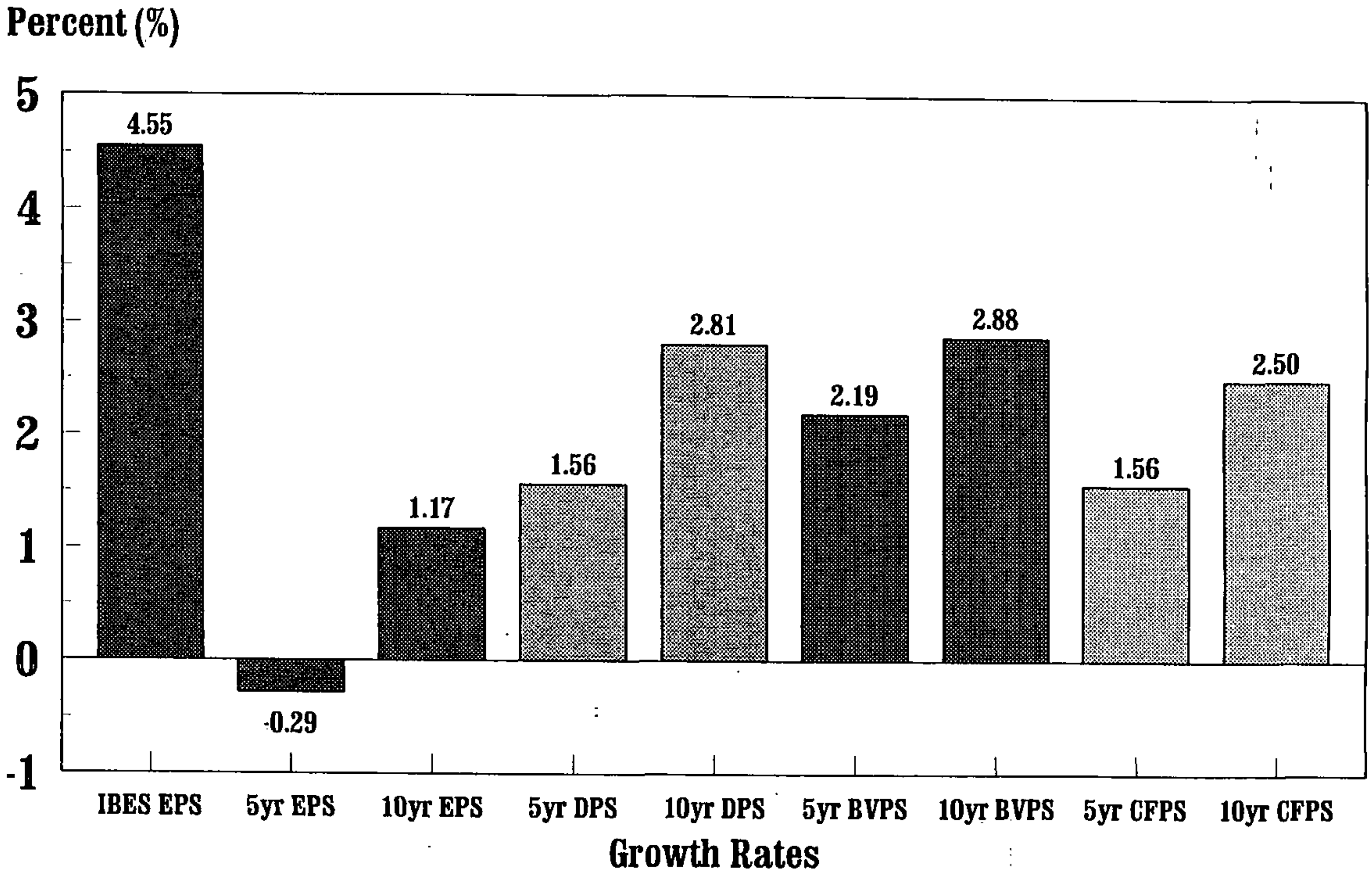
PP & L Resources, Inc.
Historical Growth Rates



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

Exhibit
Schedule 6
Page 1 of 3

Barometer Group of Eight Electric Companies
Historical Growth Rates



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

Exhibit
Schedule 6
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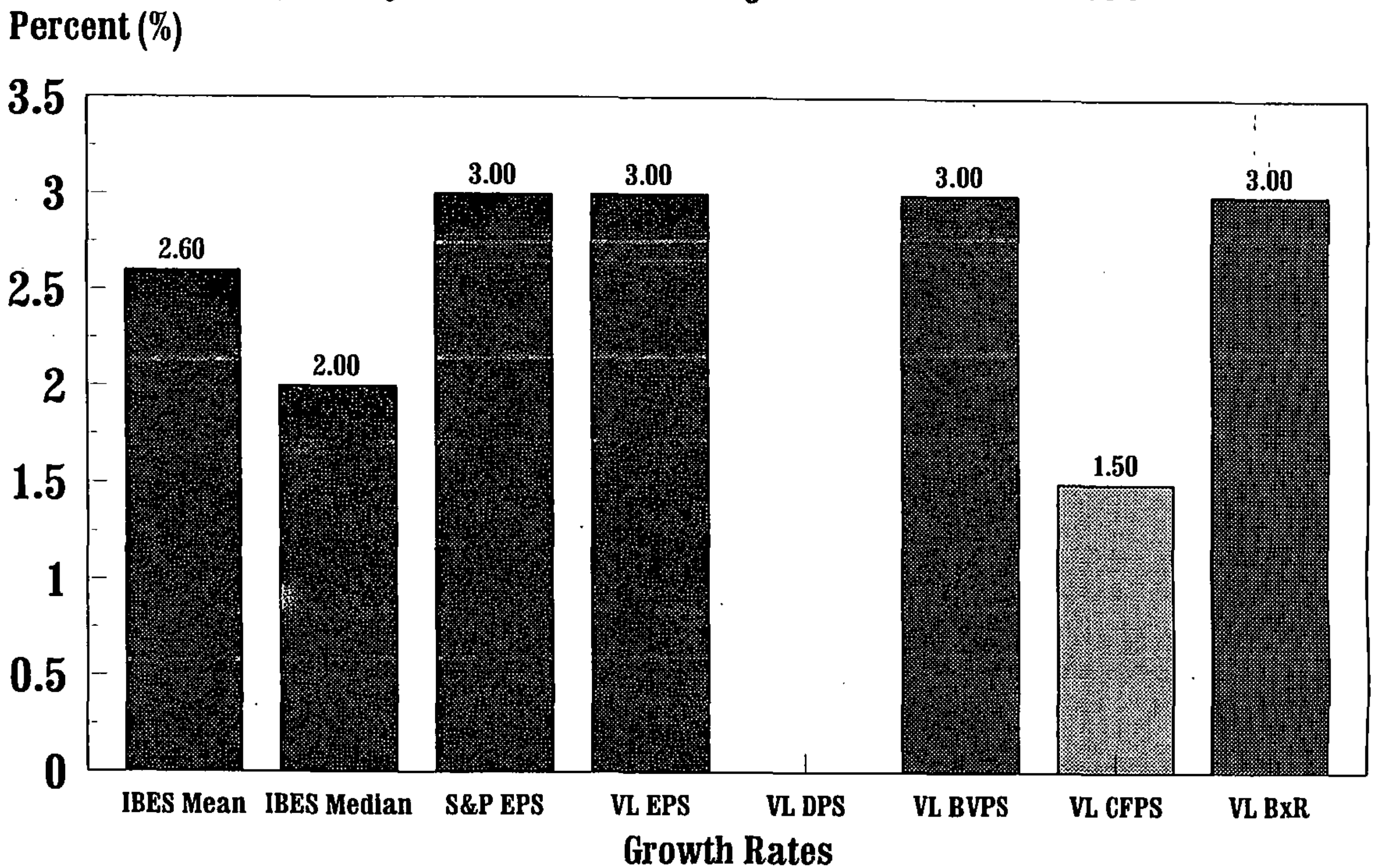
Historic Internal Growth Rates
For the Years 1991-1995

	1995	1994	1993	1992	1991	Five-Year Average	Five-Year Average Excluding Negatives
PP&L Resources Inc							
Earnings Rate on Book Common Equity	12.8%	8.8%	13.1%	13.1%	13.4%		
Dividend Rate on Book Common Equity	10.4%	10.5%	10.5%	10.4%	10.4%		
Internal Growth Rate	2.3%	-1.7%	2.7%	2.7%	3.1%	1.8%	1.8%
Barometer Group of Eight Electric Companies							
Allegheny Power System							
Earnings Rate on Book Common Equity	11.4%	10.9%	11.4%	11.6%	11.7%		
Dividend Rate on Book Common Equity	9.4%	9.7%	9.9%	10.2%	10.3%		
Internal Growth Rate	2.0%	1.3%	-1.5%	1.4%	1.4%	0.9%	1.5%
American Electric Power							
Earnings Rate on Book Common Equity	12.4%	11.9%	8.4%	11.1%	11.9%		
Dividend Rate on Book Common Equity	10.4%	10.6%	10.5%	10.5%	10.6%		
Internal Growth Rate	2.0%	1.4%	-2.1%	0.6%	1.3%	0.6%	0.3%
Atlantic Energy Inc							
Earnings Rate on Book Common Equity	9.9%	9.1%	11.7%	11.1%	12.1%		
Dividend Rate on Book Common Equity	9.8%	9.9%	10.0%	10.1%	10.5%		
Internal Growth Rate	0.1%	-0.9%	1.7%	1.0%	1.6%	0.7%	0.7%
Baltimore Gas & Electric							
Earnings Rate on Book Common Equity	10.8%	10.6%	10.4%	9.5%	9.0%		
Dividend Rate on Book Common Equity	8.3%	8.3%	8.3%	8.4%	8.4%		
Internal Growth Rate	2.5%	2.3%	2.1%	1.1%	0.7%	1.7%	1.9%
Delmarva Power & Light							
Earnings Rate on Book Common Equity	11.9%	11.3%	12.6%	12.4%	11.0%		
Dividend Rate on Book Common Equity	10.3%	10.5%	11.2%	11.4%	11.9%		
Internal Growth Rate	1.6%	0.9%	1.4%	1.0%	-1.0%	0.8%	0.5%
Dpl Inc							
Earnings Rate on Book Common Equity	14.4%	14.4%	13.7%	13.4%	11.1%		
Dividend Rate on Book Common Equity	10.9%	11.0%	10.8%	10.7%	10.4%		
Internal Growth Rate	3.5%	3.4%	2.9%	2.7%	0.7%	2.6%	2.6%
Potomac Electric Power							
Earnings Rate on Book Common Equity	4.1%	10.8%	11.9%	10.5%	12.6%		
Dividend Rate on Book Common Equity	10.3%	10.0%	10.0%	10.2%	10.6%		
Internal Growth Rate	-6.2%	0.8%	1.9%	0.4%	2.0%	-0.2%	-0.2%
Public Service Entrp							
Earnings Rate on Book Common Equity	12.3%	13.0%	12.0%	10.8%	12.1%		
Dividend Rate on Book Common Equity	9.8%	10.1%	10.5%	10.8%	10.6%		
Internal Growth Rate	2.5%	2.9%	1.5%	0.0%	1.5%	1.7%	1.7%
Average							
Earnings Rate on Book Common Equity	10.9%	11.5%	11.5%	11.3%	11.4%		
Dividend Rate on Book Common Equity	9.9%	10.0%	10.2%	10.3%	10.4%		
Internal Growth Rate	1.0%	1.5%	1.4%	1.0%	1.0%	1.1%	1.1%

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

PP & L Resources, Inc.
Analysts' Five-Year Projected Growth Rates



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

Exhibit
Schedule 7
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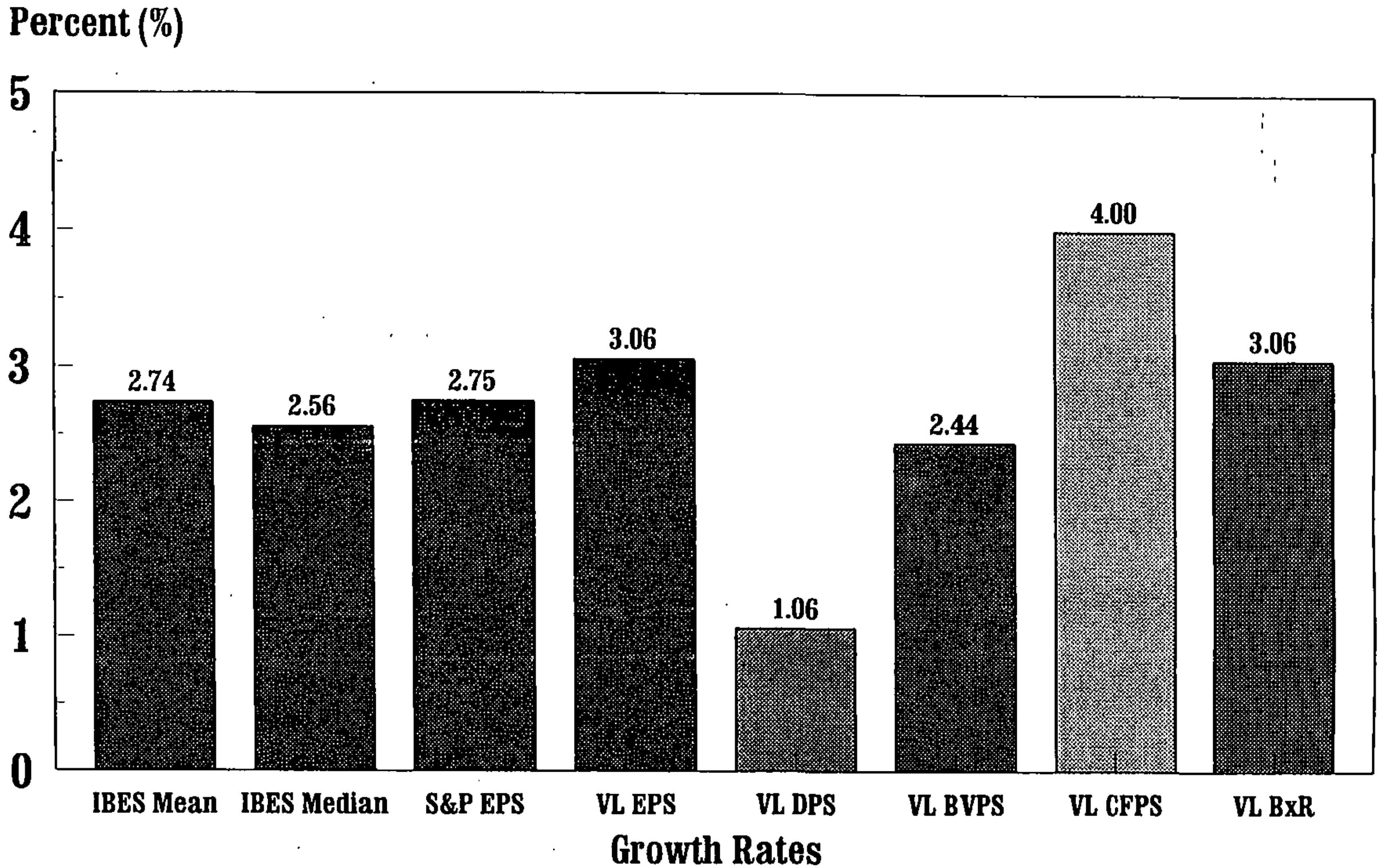
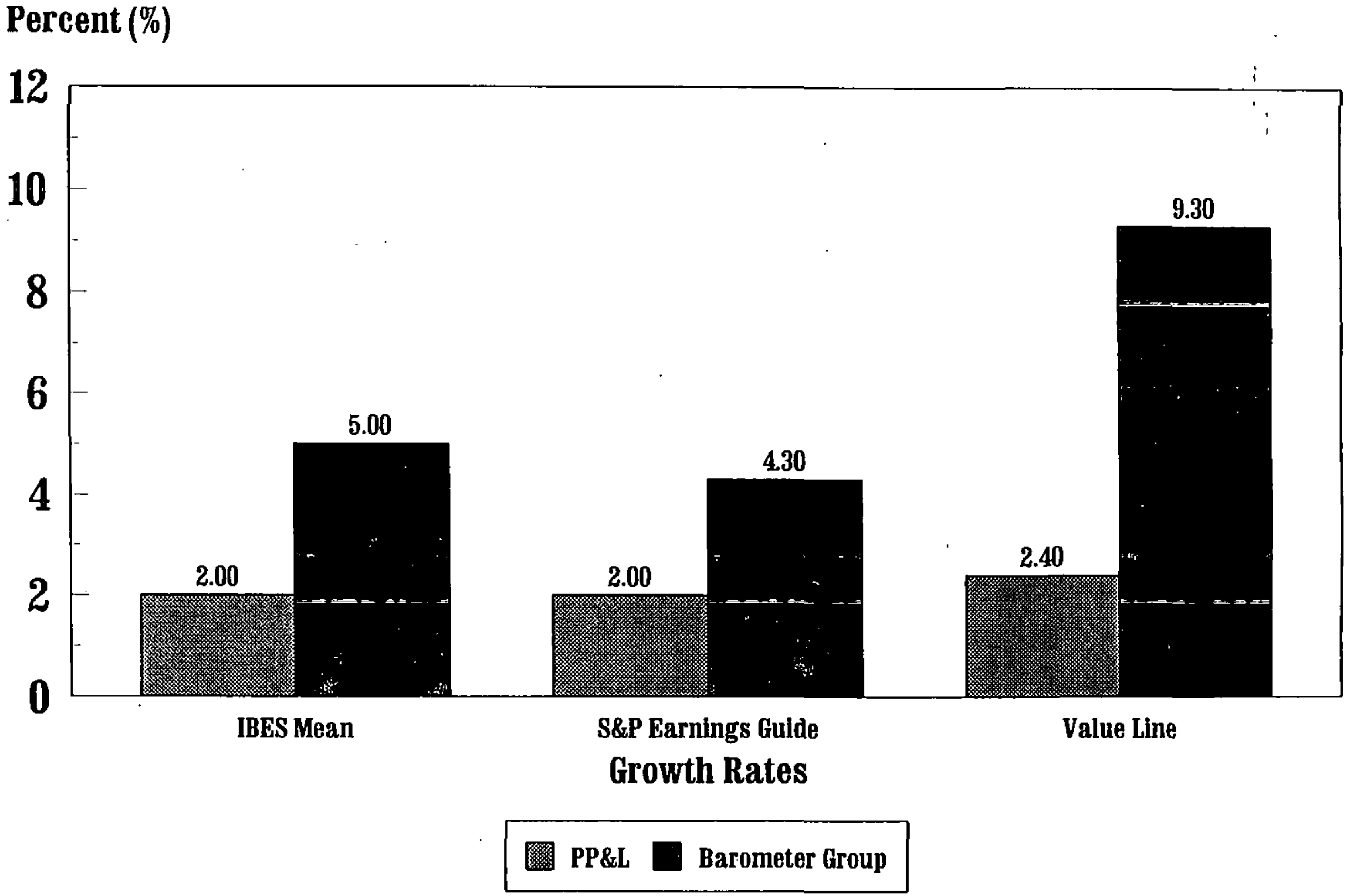
Barometer Group of Eight Electric Companies
Analysts' Five-Year Projected Growth Rates



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

PP & L Resources, Inc. and the
Barometer Group of Eight Electric Companies
Analysts' Projected Short-Run Earnings Growth Rates



PP & L Resources, Inc.
Interest Rate Trends
for Public Utility Bonds

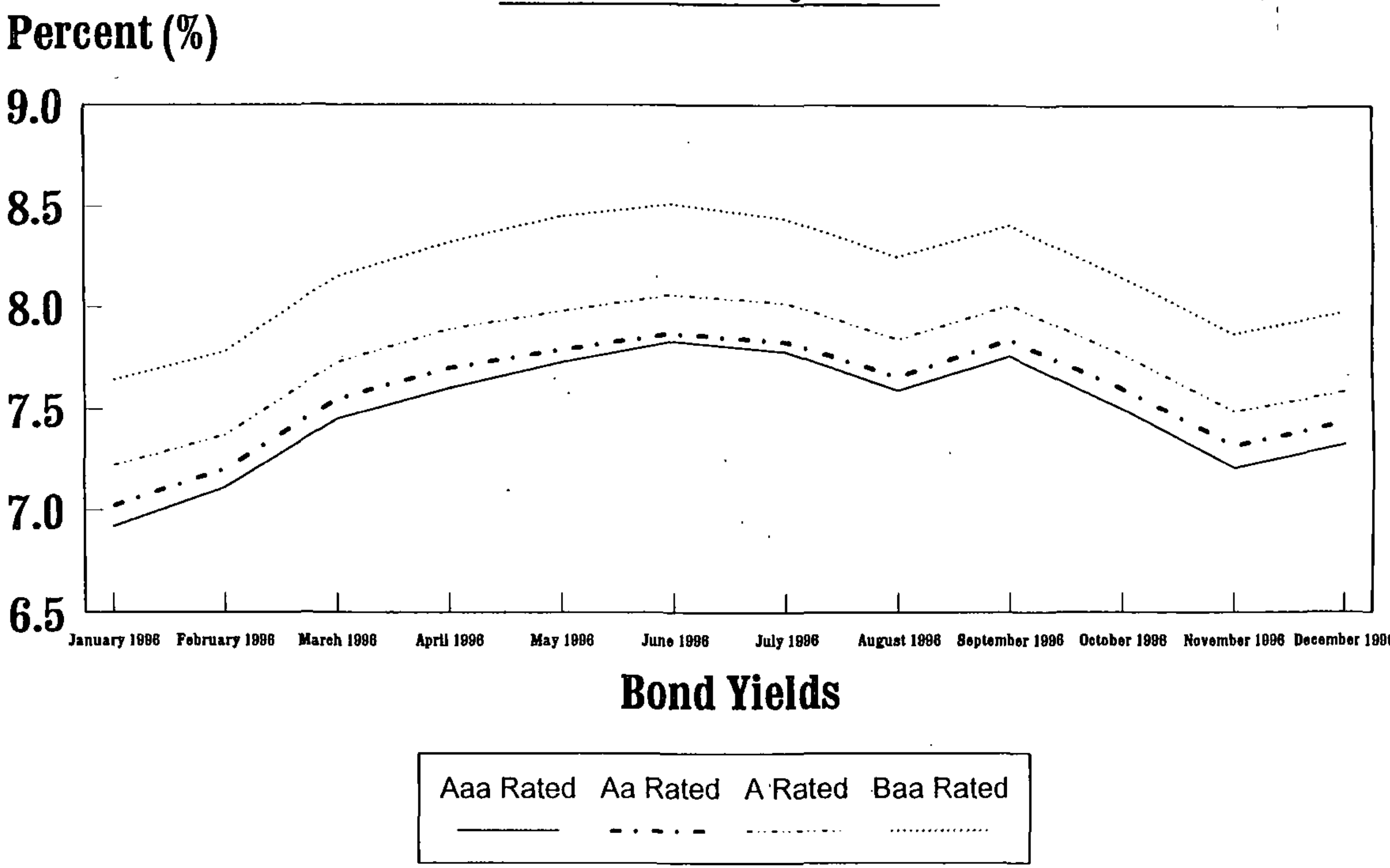


Exhibit
Schedule 8
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Interest Rate Trends for Investor-Owned Public Utility Bonds
Yearly for 1992-1996
and the Twelve Months Ended December 1996

Years	Aaa Rated	Aa Rated	A Rated	Baa Rated	Average
1992	8.19%	8.55%	8.69%	8.86%	8.57%
1993	7.29%	7.44%	7.59%	7.91%	7.56%
1994	8.06%	8.21%	8.30%	8.63%	8.30%
1995	7.68%	7.77%	7.89%	8.29%	7.92%
1996	7.48%	7.57%	7.75%	8.16%	7.74%
Months					
January 1996	6.92%	7.02%	7.22%	7.64%	7.20%
February 1996	7.11%	7.20%	7.37%	7.78%	7.37%
March 1996	7.45%	7.55%	7.73%	8.15%	7.72%
April 1996	7.60%	7.70%	7.89%	8.32%	7.88%
May 1996	7.73%	7.79%	7.98%	8.45%	7.99%
June 1996	7.83%	7.87%	8.06%	8.51%	8.07%
July 1996	7.78%	7.83%	8.02%	8.44%	8.02%
August 1996	7.59%	7.66%	7.84%	8.25%	7.84%
September 1996	7.76%	7.84%	8.01%	8.41%	8.01%
October 1996	7.50%	7.60%	7.77%	8.15%	7.76%
November 1996	7.21%	7.32%	7.49%	7.87%	7.48%
December 1996	7.33%	7.44%	7.59%	7.98%	7.58%
Twelve-Month Average	7.48%	7.57%	7.75%	8.16%	7.74%

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

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-1996

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%	19.24%
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%
Geometric Mean	10.35%	8.85%	5.58%	5.40%
Arithmetic Mean	12.33%	11.05%	5.92%	5.71%
Standard Deviation	20.39%	21.95%	8.81%	8.30%
Median	14.31%	11.26%	3.52%	4.27%

Tabulation of Risk Rate Differentials for S&P Public Utility Index and Public Utility Bonds For the Years 1928-1996, 1952-1996, 1974-1996 and 1979-1996

Total Returns	Range: Geometric Mean	Range: Median	Range: Midpoint	Point Estimate: Arithmetic Mean	Average of Midpoint and Point Estimate
1928-1996					
S&P Public Utility Index	8.85%	11.26%		11.05%	
Public Utility Bonds	5.40	4.27		5.71	
Risk Differential	3.45%	6.99%	5.22%	5.34%	5.28%
1952-1996					
S&P Public Utility Index	11.57%	11.74%		12.69%	
Public Utility Bonds	6.24	4.65		6.60	
Risk Differential	5.33%	7.09%	6.21%	6.09%	6.15%
1974-1996					
S&P Public Utility Index	14.74%	14.61%		16.06%	
Public Utility Bonds	9.75	10.19		10.20	
Risk Differential	4.99%	4.42%	4.71%	5.86%	5.28%
1979-1996					
S&P Public Utility Index	16.29%	14.85%		17.20%	
Public Utility Bonds	10.74	10.26		11.18	
Risk Differential	5.55%	4.59%	5.07%	6.02%	5.55%

Merrill Lynch and Value Line
Adjusted Betas for PP&L Resources Inc., and the
Barometer Group of Eight Electric Companies

	Merrill Lynch Adjusted Beta	Value Line Adjusted Beta	Average Adjusted Beta
PP&L Resources Inc	0.77	0.75	0.76
Barometer Group of Eight Electric Companies			
Allegheny Power System	0.71	0.70	0.71
American Electric Power	0.70	0.70	0.70
Atlantic Energy Inc	0.65	0.70	0.68
Baltimore Gas & Electric	0.85	0.85	0.85
Delmarva Power & Light	0.58	0.70	0.64
Dpl Inc	0.60	0.70	0.65
Potomac Electric Power	0.81	0.80	0.81
Public Service Entrp	0.87	0.80	0.84
Average	0.72	0.74	0.73

Source of Information : Merrill Lynch Security Price Index, January 1997
Value Line Investment Survey, December 13, 1996 and October 11, 1996

PP & L Resources, Inc.
Interest Rate Trends
for Treasury Constant Maturities

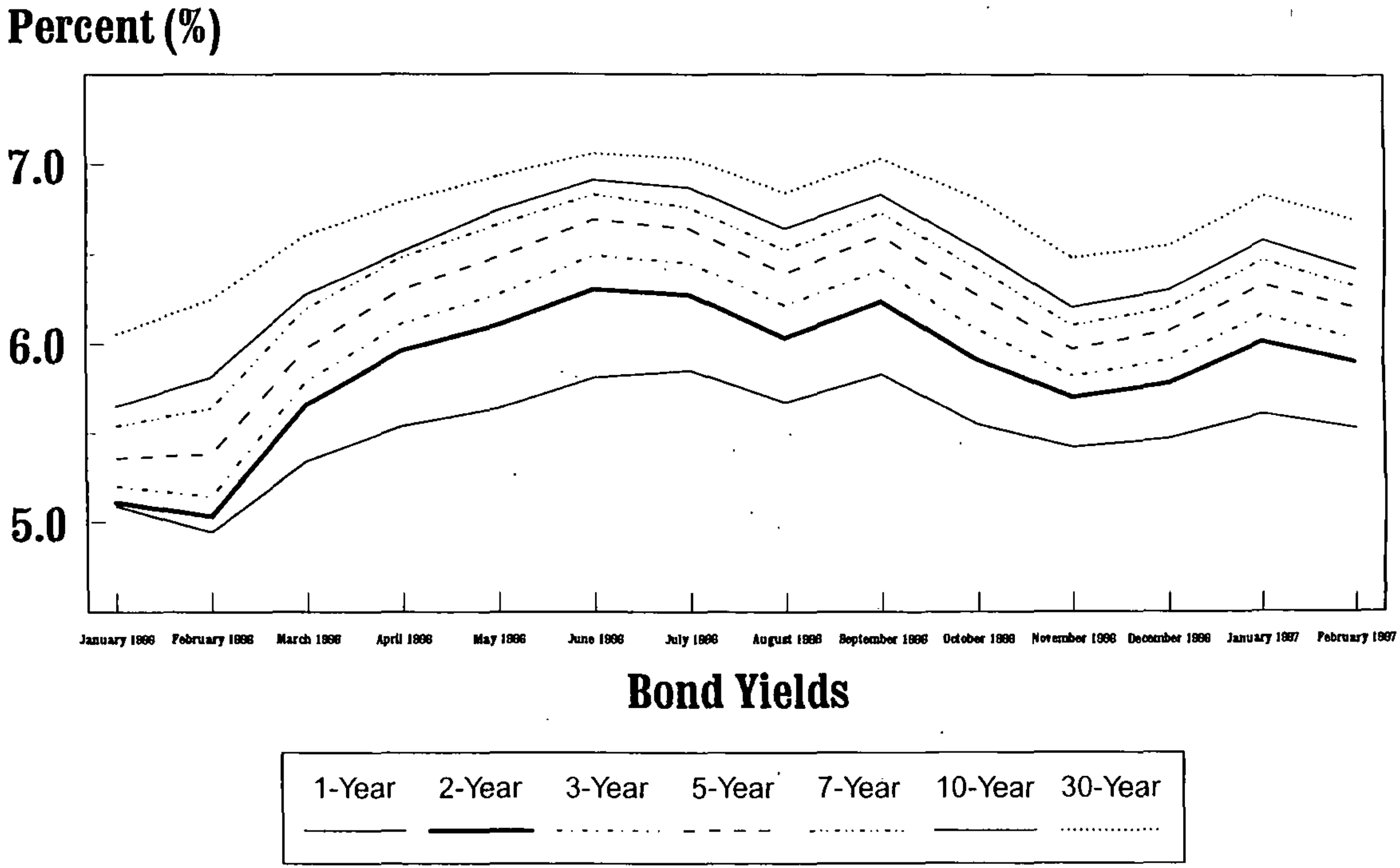


Exhibit
Schedule 10
Page 2 of 7

Interest Rate Trends for Treasury Constant Maturities
Yearly for 1992-1996
and the Twelve Months Ended December 1996

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	30-Year
1992	3.89%	4.77%	5.31%	6.19%	6.63%	7.01%	7.67%
1993	3.43%	4.05%	4.44%	5.15%	5.55%	5.87%	6.60%
1994	5.31%	5.94%	6.26%	6.68%	6.90%	7.08%	7.37%
1995	5.95%	6.16%	6.26%	6.39%	6.50%	6.58%	6.88%
1996	5.51%	5.84%	5.99%	6.18%	6.34%	6.44%	6.70%
Months							
January 1996	5.09%	5.11%	5.20%	5.36%	5.54%	5.65%	6.05%
February 1996	4.94%	5.03%	5.14%	5.38%	5.64%	5.81%	6.24%
March 1996	5.34%	5.66%	5.79%	5.97%	6.19%	6.27%	6.60%
April 1996	5.54%	5.96%	6.11%	6.30%	6.48%	6.51%	6.79%
May 1996	5.64%	6.10%	6.27%	6.48%	6.66%	6.74%	6.93%
June 1996	5.81%	6.30%	6.49%	6.69%	6.83%	6.91%	7.06%
July 1996	5.85%	6.27%	6.45%	6.64%	6.76%	6.87%	7.03%
August 1996	5.67%	6.03%	6.21%	6.39%	6.52%	6.64%	6.84%
September 1996	5.83%	6.23%	6.41%	6.60%	6.73%	6.83%	7.03%
October 1996	5.55%	5.91%	6.08%	6.27%	6.42%	6.53%	6.81%
November 1996	5.42%	5.70%	5.82%	5.97%	6.10%	6.20%	6.48%
December 1996	5.47%	5.78%	5.91%	6.07%	6.20%	6.30%	6.55%
Twelve-Month Average	5.51%	5.84%	5.99%	6.18%	6.34%	6.44%	6.70%

Source of Information : Federal Reserve Statistical Release

Measures of the Risk Free Rate
Using Blue Chip Financial Forecasts

The forecast 30-year Treasury Bond yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated January 1, 1997.

	Treasury Note Yield 10-Year	Treasury Bond Yield 30-Year
First Quarter 1997	6.3%	6.5%
Second Quarter 1997	6.3	6.5
Third Quarter 1997	6.3	6.5
Fourth Quarter 1997	6.3	6.5
First Quarter 1998	6.3	6.5
Second Quarter 1998	6.3	6.5

Source of Information: Blue Chip Financial Forecasts, January 1, 1997.

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.

December 27, 1996

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

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

15.7

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

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

2.2%

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

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

50%

26 Weeks Ago*	Market Low 12-23-74*	Market High 9-4-87*
50%	234%	40%

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

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

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

*Reviewed in this week's edition.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LII, No. 16.
Published weekly by VALUE LINE PUBLISHING, INC. 220 East 42nd Street, New York, N.Y. 10017-5891

Capital Asset Pricing Model
Component Inputs
Market Return for the Standard & Poor's 500 Index

Standard & Poor's 500

Data Values		Computations	
Dividends	14.89		
		Adjusted Yield (2)	2.08%
Price Index	757.02	5-Year Projected Earnings Growth	12.00
Dividend Yield (1)	1.97%	DCF Result (3)	14.08%

Notes: (1) Dividend Yield is the result of the index dividend amount divided by the index price reported in the S&P Stock Guide.
(2) Adjusted dividend yield reflects an adjustment for next period dividend payments of 1 + 0.5g.
(3) The growth rate for the S&P 500 is the 5 year projected Eps growth rate reported in the S&P Earnings Guide.
(4) DCF results equals the adjusted dividend yield plus the projected 5-Years Earnings Growth fo the Index from the S&P Earnings Guide.

Source of Information: Standard & Poor's Earnings Guide - December 1996
Standard & Poor's Stock Guide - December 1996

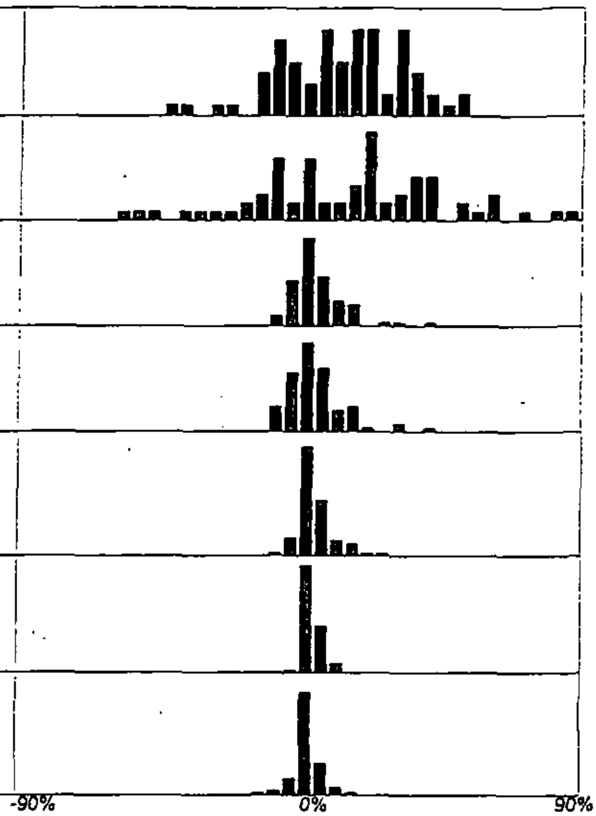
Table 2-1

**Basic Series:
Summary Statistics of
Annual Total Returns**

Exhibit
Schedule 10
Page 7 of 7

From 1926 to 1996

Series	*Geometric* Mean	*Arithmetic* Mean	*Standard* Deviation	Distribution
Large Company **Stocks**	10.7%	12.7%	20.3%	
Small Company Stocks	12.6	17.7	34.1	*
Long-Term Corporate Bonds	5.6	6.0	8.7	
Long-Term Government	5.1	5.4	9.2	
Intermediate-Term Government	5.2	5.4	5.8	
U.S. Treasury Bills	3.7	3.8	3.3	
Inflation	3.1	3.2	4.5	



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

Comparable Earnings Approach for PP & L Resources, Inc. and
the Barometer Group of Eight Electric Companies
All Value Line Non-Utility Companies with Timeliness of 4 and 5,
Safety Ranking of 2 and 3, Financial Strength of B++ and A,
Price Stability 75 and Higher, Beta's Between .70 and .85
and Technical Rank of 3 and 4.

Company Name	Industry Name	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
BANDAG, INC.	Tire/Rubber	4	2	A	90	0.75	4
CHRIS-CRAFT	Entertainment	4	2	B++	85	0.85	3
GIANT FOOD 'A'	Grocery	4	2	B++	85	0.70	3
HORMEL FOODS	Food Processing	4	2	A	85	0.75	4
LEARONAL INC.	Chemical: Spec	5	3	B++	75	0.75	4
LEE ENTERPRISES	Newspaper	4	2	A	90	0.80	3
OHIO CASUALTY	Insurance: P/C	4	2	B++	75	0.80	4
OLD KENT FIN'L	Bank: Midwest	4	2	B++	90	0.75	3
ROLLINS, INC.	Industrial Svcs	5	2	A	75	0.85	3
ST. PAUL COS.	Insurance: P/C	5	2	B++	90	0.80	4
STANHOME INC.	Retail: Spec'l	4	2	A	80	0.80	4
UNITRIN, INC.	Insurance: Divr	4	2	A	85	0.80	3
WILMINGTON TR	Bank	4	2	A	85	0.85	3
Averages		4.2	2.1	A	83.8	0.79	3.5
PP&L Resources. Inc.		4.0	2.0	B++	95.0	0.75	4.0
Barometer Group	- Average	4.3	2.3	A	96.9	0.74	3.8
	- Range	4 to 5	2 to 3	B++ to A	90 to 100	.70 to .85	3 to 4

Source of Information: Value Line - Value Screen Data Base, January 1997

Comparable Earnings Approach
Five Year Average Historical Earned Returns
for the Years 1991-1995 and
Projected 3-5 Year Returns

Company Name	1991	1992	1993	1994	1995	Average	Projected 3-5 Year Return
BANDAG, INC.	26.8%	24.8%	19.1%	21.7%	24.3%	23.3%	17.5%
CHRIS-CRAFT	5.5%	5.9%	11.8%	5.0%	1.7%	6.0%	4.5%
GIANT FOOD 'A'	14.0%	12.3%	12.8%	12.5%	12.4%	12.8%	13.5%
HORMEL FOODS	14.8%	14.8%	17.7%	17.8%	16.5%	16.3%	16.5%
LEARONAL INC.	9.8%	10.7%	11.5%	12.2%	14.0%	11.6%	14.0%
LEE ENTERPRISES	17.2%	18.9%	18.5%	21.0%	18.8%	18.9%	16.5%
OHIO CASUALTY	13.9%	11.8%	10.1%	10.7%	8.6%	11.0%	13.0%
OLD KENT FIN'L	13.8%	15.3%	15.7%	15.8%	14.0%	14.9%	14.0%
ROLLINS, INC.	30.0%	29.3%	27.7%	25.6%	21.8%	26.9%	20.0%
ST. PAUL COS.	15.2%	5.5%	14.2%	16.2%	14.0%	13.0%	15.5%
STANHOME INC.	18.7%	18.2%	17.5%	16.4%	15.7%	17.3%	16.5%
UNITRIN, INC.	7.3%	8.4%	4.5%	8.4%	9.9%	7.7%	10.5%
WILMINGTON TR	20.8%	20.9%	20.9%	20.4%	19.6%	20.5%	19.5%
Average						15.4%	14.7%

Source of Information: Value Line - Value Screen Data Base, January 1997
Value Line Investment Survey (Various Editions)

Simple DCF Results for the Comparable Earnings Group for PP & L Resources, Inc. and the Barometer Group of Eight Electric Companies

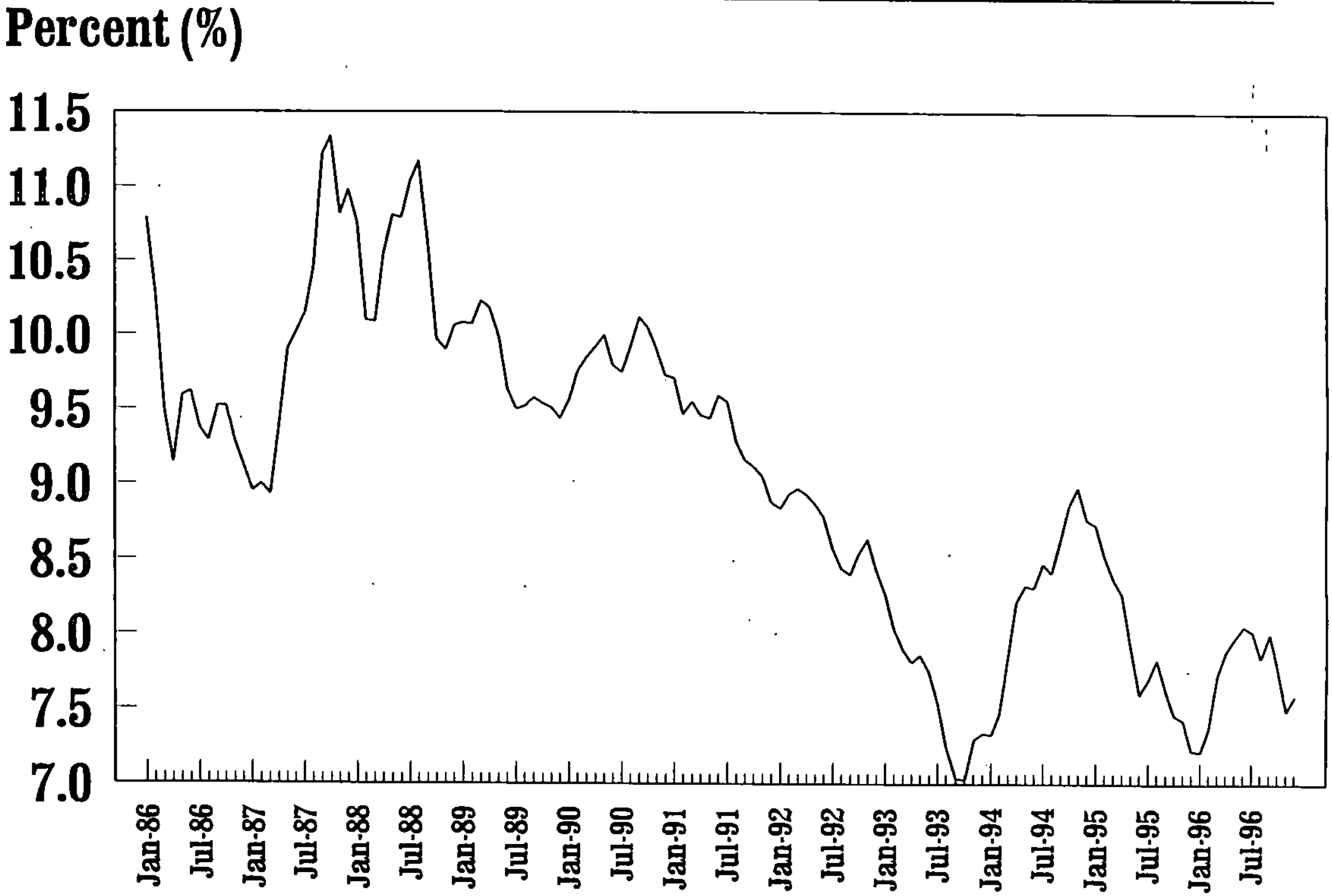
Company Name	Industry Name	Dividend Yield	Projected Earnings Growth Rate	DCF Result
BANDAG, INC.	Tire/Rubber	2.1%	4.5%	6.6%
CHRIS-CRAFT	Entertainment	0.0%	NMF	NMF
GIANT FOOD 'A'	Grocery	2.3%	11.0%	13.3%
HORMEL FOODS	Food Processing	2.6%	7.5%	10.1%
LEARONAL INC.	Chemical: Spec	3.4%	13.0%	16.4%
LEE ENTERPRISES	Newspaper	2.3%	11.5%	13.8%
OHIO CASUALTY	Insurance: P/C	4.9%	12.0%	16.9%
OLD KENT FIN'L	Bank: Midwest	3.1%	7.0%	10.1%
ROLLINS, INC.	Industrial Svcs	3.1%	1.0%	4.1%
ST. PAUL COS.	Insurance: P/C	3.3%	8.5%	11.8%
STANHOME INC.	Retail: Spec'l	4.0%	7.5%	11.5%
UNITRIN, INC.	Insurance: Divr	4.5%	11.5%	16.0%
WILMINGTON TR	Bank	3.5%	11.0%	14.5%
Average				12.1%

Source of Information: Value Line - Value Screen Data Base, January 1996
Value Line Investment Survey - various issues

EXHIBIT PRM 3

Interest Rate Trends from January 1986 to December 1996

Moody's A Rated Public Utility Average Monthly Yields



Bond Yields

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 7

Direct Testimony of Scott T. Jones, Ph.D.

I INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott T. Jones. My business address is One Mifflin Place, Cambridge, Massachusetts, 02138.

Q. What position do you hold?

A. I am CEO, The Economics Resource Group, Inc. My firm specializes in economic and regulatory policy consulting services to private and, to a lesser extent, public organizations in traditionally regulated industries.

II QUALIFICATIONS AND EXPERIENCE

Q. Please describe your educational background and prior work experience.

A. I have been involved in issues related to the regulation of utilities and regulatory policy for 12 years. My experience with regulated utilities and regulatory policy includes research and testimony on behalf of clients as well as working with regulators at the state and federal level as a senior executive in the energy industry. Over this period, I have been directly involved with matters that are the subject of this proceeding, particularly matters pertaining to the transition of a regulated industry to a more competitive environment. My previous work experience and testimony includes rate design, the role of regulation in project economics, the determination of workably competitive markets and market prices, facilities siting, resource cost analysis, and financial economics pertaining to tariff structure, mergers and debt refinancing. I have acted as a consultant and as a member of the energy industry in matters pertaining to electric utilities, oil pipelines, natural gas pipelines and natural gas liquids pipelines.

My experience in the energy industry, including forecasting and market price determination, spans 22 years. Over this period, I have worked in the oil and gas industry on two occasions. I hold a Ph.D. in Economics from Virginia Tech. My resume is attached as Exhibit STJ 1, listing my background and experience in further detail.

III PURPOSE AND CONCLUSIONS

Q. What is the purpose of your testimony?

A. Pennsylvania Power and Light Company ("PP&L" or the "Company") has asked me to provide estimates for the price of electricity in a competitive retail and wholesale environment. Given that price estimate, I have been asked to compute the expected revenue generated by each PP&L generating facility over its remaining plant life.

These price estimates and generating plant revenue estimates are used as inputs to the Company's calculation of stranded cost, as described in the testimony of Mr. Joseph Schadt. The market price estimates are also an input into PP&L's proposed rate design, as described in the testimony of Dr. Susan Tierney, Mr. Douglas Krall, Mr. Joseph Kleha and Mr. Oliver Kasper.

Q. Please state the scope of your testimony and any conclusions.

A. I will explain each of the key assumptions and explain anticipated market conditions as they affect the forecasted market price. I will explain how PP&L's dispatch model was used to derive hourly market-clearing prices in the Pennsylvania-New Jersey-Maryland Power Pool ("PJM"), inclusive of imports and exports. I will explain the role of the capacity market and how capacity prices are formed. I will explain the role of the energy market and how energy prices are formed. I will discuss how the market prices are used to estimate generation revenues of PP&L plants and how those revenue estimates are used by other witnesses to calculate stranded costs.

The prices I have produced for energy and capacity reflect the market conditions and assumptions that are expected to prevail in PJM beginning in 1999. All plants in PJM will be subjected to these prices, including those owned by PP&L. Market prices are assumed to determine generating plant revenue. The prices are lower than the full cost of service rate regulation, suggesting that consumers will be able to directly observe the beneficial effects of competition on their unbundled rates, net of the unbypassable competitive transition charge, during the transition from regulated monopoly service to fully competitive supply service.

IV OVERVIEW: KEY POLICY AND MARKET FACTORS

Q. Please identify the policy context in which your market price estimates and projections of generation-related revenue have been developed.

A. The Commonwealth of Pennsylvania has passed the Electricity Generation Customer Choice and Competition Act ("Act") which requires electric utilities in the state to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers beginning in 1999. The Act calls for retail choice to be fully instituted within three years, so that all residents of the state will have the opportunity to decide which generation company will supply their electricity. Customer choice and retail access are intended to replace the regulated generation of electricity as a public utility function.

Q. Please describe the nature of the market in which PP&L's generation facilities will operate as part of a restructured electric industry.

A. In the future competitive generation market, each plant PP&L has in service can expect to receive the current competitive price for the electricity it provides as determined by market forces. An independent system operator ("ISO"), presumably formed within the PJM control area, will ensure reliability for Pennsylvania customers by dispatching the generation units within the power pool. Under the current PJM proposal, the regional power market would also perform market functions associated with the short-term markets for electric energy, capacity, and ancillary services. Suppliers, like PP&L, seeking to supply load in the PJM-ISO region will bid prices into the regional capacity and hourly energy markets. These bids represent the prices at which generators are willing to supply electric generation services. If they are called upon in any hour, generators will behave as "price-takers", receiving a market price for the electricity they generate. In competitive markets, where suppliers receive the market clearing price, producers will tend to bid their generation at its marginal cost. The variable costs of the last generation facility dispatched will determine price, rather than sunk investment costs. In such a system, competition is fostered through the activities of each generator, acting in its own self-interest, which together produce electricity at the lowest possible cost.

Q. In a competitive environment, what are the components and component markets that will determine the market prices for electricity?

A. Electricity prices are based on prices in two component markets: energy and capacity. These two markets satisfy two different forms of demand for electricity: the capacity requirements of producers and the demand for power supplied by the energy market. These two markets have different attributes, costs, and key variables. However, both markets are expected to clear at prices which approximate variable cost.

Q. What do you mean by the market "clearing" at prices which approximate variable cost?

A. Firms in competitive markets are driven by the cost of production. Competition among sellers will act to drive market prices toward the incremental cost of production. Hence, the factors affecting the market price for energy are those that make up the direct cost of generating electricity, such as fuel, variable operating and maintenance ("O&M") costs, and any regulatory costs associated with generation (e.g., the cost of emissions allowances).

The factors that determine the capacity component of electricity prices include the short-term costs associated with the last capacity-holder that succeeds in making its capacity available to the system. In an excess capacity situation, those costs tend to be the incremental fixed costs of keeping a plant available for operation (e.g., a single year's fixed O&M costs, any necessary investment, and taxes). In a capacity deficit period, the marginal cost of capacity would tend toward the cost of adding new capacity.

Q. What method is used to estimate annual revenue from each of PP&L's facilities?

A. Once the market price of electricity is estimated, based on energy and capacity market prices, the annual revenues for each of PP&L's plants are derived in two basic steps. The first step determines the amount of expected revenue from capacity sales. The second step, using the Company's "EGEAS" model[1], determines the amount of expected revenue from energy sales.

Q. Has PP&L's EGEAS model been used as part of other proceedings before the Pennsylvania Public Utility Commission ?

A. Yes. EGEAS has been used to generate estimates in documents that have been cited in Commission proceedings or used to meet other regulatory requirements. From 1994-96, EGEAS was used to help produce PP&L's Annual Resource Planning Report, PURPA 210 avoided cost filings, the Energy Information Administration's 767 filings

[1] EGEAS is a model developed by The Electric Power Research Institute (EPRI) and used by numerous electric utilities.

for fuel forecasts, and PP&L's data provided to the Global Climate Challenge filings which track CO_2 emission reductions.

V THE PRICE OF ELECTRICITY AND THE STRUCTURE OF THE MARKET IN PJM

Q. What is the scope of the relevant market that will determine prices in a competitive market for energy or capacity?

A. At the very least, the supply-side of the relevant generation market facing PP&L appropriately includes the generation sources in and available to the PJM region. This includes all of the power sources in PJM, and energy and capacity that can be delivered to PJM over lines connecting other regions to PJM. The demand-side of the relevant generation market should include all customers in and with access to electricity that can be delivered over lines within and connected to PJM.

Q. How will electricity prices be formed in PJM?

A. In tomorrow's competitive generation markets, electricity prices will be formed by forces of supply and demand brought to bear on its two component (product) markets, energy and capacity. In the short run, the price for energy will reflect the variable cost of producing power from generation equipment. This is primarily the fuel and other costs that rise and fall in proportion to the amount of time and the output of the generators on-line and producing power. Therefore, the fuel and variable O&M of the least-efficient producer in any hour will set the market clearing price in that hour.

By contrast, the short-term capacity price is driven largely by the amount of installed generation capacity available in each area at that particular point in time. If there is more capacity available than demanded--the current situation in PJM--the price for capacity will be low, since there is surplus capacity. As capacity tightens, capacity prices are likely to rise to the level required to install the lowest-cost new capacity additions.

Each of these two markets, energy (kilowatt-hour, or kwh) and capacity (kilowatt, or kW), is expected to undergo identifiable structural changes. These changes result from the continuing increase in wholesale competition and the move toward retail competition brought about by the forces of economics, technology and law, including the changes mandated by the Act. For example, with the introduction of retail competition, short-term incremental cost of generating electricity may decline. Since customers will have the option to buy electricity from the generator of their choice and they will see lower energy rates, lower incremental energy costs should stimulate demand. Growing electricity demand should continue to absorb existing generation capacity, causing the incremental cost of capacity to gradually rise.

Q. What are some of the key elements that are going to impact the price of energy following the introduction of retail competition to the electric industry in Pennsylvania?

A. The energy market sets the kilowatt-hour (kwh) price for electricity. The energy price is driven mainly by the incremental cost of fuel required to generate electricity. Depending on the type of generation equipment, the fuel used may be coal, uranium, oil (residual fuel or distillate), natural gas, or water (hydroelectric facilities), or other renewable energy. In addition, the incremental cost of energy depends on variable O&M costs.

Energy prices may be affected by system constraints within PJM. There are times when PJM is constrained at its Eastern transfer limit. This constraint may effect economic dispatch. Lower cost energy on the Western side of the constraint is unable to reach certain areas within the Eastern area of PJM, so higher cost generation must run in the East to meet incremental load requirements in those areas.

Q. What are some of the key elements that are going to effect the price of capacity in a competitive market?

A. The capacity market sets the kilowatt (kW) price for electricity. The incremental capacity price is driven by the mix and availability of generation equipment that can be dispatched within PJM, or relied upon by PJM as delivered over the inter-ties with neighboring regions. Given the present surplus of capacity, this market clears near the net cost of keeping capacity in operation. Depending on the expected prices of energy and capacity in the future, generators may decide to add new capacity. In the future, there will be a competitive incentive to add new capacity if prices rise sufficiently to induce the addition of new efficient units, such as combined cycle units, with lower fuel and operating costs. In order for companies to commit capital for new generation equipment, the expected competitive market price (combined energy and capacity prices) must be high enough to offer a return on capital as well as cover incremental operating costs.

An important determinant of expectations about electricity prices is the demand for electricity. As demand grows, existing capacity is absorbed. As capacity is absorbed, short-term prices for capacity will rise, eventually coaxing new capacity into the competitive market. Putting new capacity to work generating electricity in place of existing capacity may or may not increase the demand for fuel, depending on the size, age, and type of generation capacity it displaces.

V A. The Energy Market (kwh)

Q. How is the post-1999 competitive market for electric energy likely to operate within PJM?

A. The bid prices for electricity within PJM should closely reflect the variable cost of each unit bidding in any hour. The hourly market clearing price within PJM will reflect the variable cost of the last unit dispatched to meet the energy requirements.

Currently, PJM serves 22 million customers within 50,000 square miles from Virginia to New York and west to the Ohio border using about 8 percent of the nation's generation capacity. The vast majority of PJM's approximately 56,000 MW of capacity (1996 summer peak) is steam generation equipment, fueled largely by coal and nuclear fuels. Additionally, hydroelectric units compose about 5% of capacity. Combined cycle ("CC") units, some of which are operated by non-utility generators, integrate the best feature of rapid-starting turbines with the economy of low heat rates. Combustion turbine ("CT") and diesel generators are normally used to meet peaking capacity requirements.

Part of PJM's demand is, of course, met through power interchange (imports/exports) that results from agreements and physical interconnections with the pools, systems and companies bordering the PJM area. Imports of power result in the receipt of low cost electricity from great distances.

Subject to various constraints on the interconnections that move power between other regions and PJM, individual companies within PJM and PJM itself arrange for the purchase and sale of generation with power sources in neighboring pools and systems such as those to the west which operate with less expensive coal-fired generation. These imports of power are used whenever possible and economical, providing part of the system's base energy supply.

Given this mix of existing generation facilities within and available to PJM, the price of energy in any hour is a function of the mix of available units, including imports, their relative efficiencies, and their fuel and operating costs and the demand for energy. With demand levels rising and falling over the course of the day and night, and across seasonal peaks, the spot price in any hour is set by the marginal unit needed to meet demand.

As noted previously, transmission constraints within PJM sometimes cause the PJM system to separate into two or more "sub-markets" for energy during certain hours of the year. Prices in these sub-regional markets will vary during those hours.

Q. Can you explain how transfer limits within PJM affect PP&L?

A. Exhibit STJ 2 contains several pages of tables with data and graphs showing the effect and extent of the western, central and eastern transfer limits and how electricity prices are affected in PP&L.

The one recurring constraint is the eastern transfer limit that forms along the border between PP&L and the PJM companies that lie electrically to the east of PP&L. (See Exhibit STJ 2, page 5). When PJM load and supply characteristics cause the flow of large volumes of economical power from western to eastern PJM, the transfer limit may be reached, at which point additional economical supplies in the west can no longer be called upon to satisfy incremental demand in the east.

This is best explained with graphs that appear on pages 2 and 3 of Exhibit STJ 2. These two graphs are two days showing the system lambdas, or the effect of changes in electricity use during the day on the hourly price of electricity. These graphs show, simultaneously, the lambdas for the portions of PJM lying on either side of the eastern constraint. The graphs show that as the day progresses, from midnight near the vertical axis to mid-day near the center of the horizontal axis, electricity use grows to the point where the power transfer capability from the area west of the constraint to east of the constraint is "maxed-out". When that happens, prices rise for customers to the east and fall, or remain constant, for customers to the west of the constraint.

Q. Is this a persistent problem in PJM?

A. The extent that the eastern transfer limit economically constrained PJM is summarized on page 4 of Exhibit STJ 2 in a table titled

"Frequency and Magnitude of the Eastern Constraint in PJM, 1992-1996".

Q. What do you mean by "economically constrained" PJM?

A. One of the first things that PP&L's system engineers told me when I asked about the effect of the Eastern constraint on prices in PJM was, "You cannot look at the number of hours that PJM reports as constrained." The engineers noted that PJM reports the system as constrained for an hour if it is constrained for the entire hour or only a few seconds of the hour. If one or more of the system lambdas, which are reported every 20 seconds of every hour, indicates the constraint is affecting the system, then that hour is recorded as being constrained. For example, in 1996, PJM reports that for 15% of the hours the system was in operation, the Eastern constraint affected the system.2 However, my examination of the system lambdas was limited to those hours where, on average, the Eastern constraint created an economic impact on the region, or where the average hourly price east and west of the constraint differed. If the constraint

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[2] "Report on Interconnection Operation, December 1996" PJM Interconnection Association, January 1997, p. 10.

lasted for a few seconds before being corrected, then average hourly lambdas would show no record of an economic impact on the system.

The data on page 4 of Exhibit STJ 2 indicate that the price effect was one mill or greater only 2.45% of the time over the five years from 1992-96. A one mill differential in price was selected because while it is small, it is still a distinct difference, at approximately 4% of the historical average price of electricity when the eastern transfer limit begins to affect the system. In other words, customers to the east of the constraint will face electricity prices that are at least 4% greater than prices to the west one hour in forty, on average, throughout the year.

Q. Why is this fact important to your market price testimony?

A. It demonstrates the insignificance of the constraint to long-term forecasts of market prices. While I have provided the facts to show that the constraint is real, to an economist it is not a large, recurring factor in the way annual average electricity prices are determined in PJM.

Q. Are spot market transactions the only way power is going to be bought and sold in a competitive environment?

A. No. While I anticipate that spot transactions will dominate the way price is set for the majority of electricity transactions within PJM, bilateral contracts will be executed between generating companies and certain customers, especially certain industrial and large commercial accounts. For that matter, bilateral agreements exist today and will continue to be used whenever one or more parties to the transaction think they can benefit from tailoring the terms and conditions of the transaction. Even so, I expect that over time, the price of electricity sold under bilateral contracts will approximate the prices for spot transactions of electricity. For this reason, I assume that market prices will approximate the short-term marginal cost of generating electricity.

Q. How will spot prices for energy be reported in the PJM competitive market?

A. I expect that spot prices will be transparent, i.e. readily available, electronically, in real-time or near real-time. It is probable that the PJM regional power market will report spot prices for electricity in a way that will encourage use of the spot market.

I hold this view based on my experience in natural gas pipeline markets. When the merchant function of gas pipelines was deregulated, the natural gas industry benefited from the emergence of electronic bulletin boards, where pipeline capacity could be matched with spot gas supplies at "hubs" throughout the interstate natural gas pipeline system. Hub pricing quickly emerged as the dominant market force within the industry. A similar, fully integrated system is likely to emerge for electricity since parts of that system are already in place. For example, electricity futures markets currently operate in the western U.S. and utilities within PJM already operate an electronic bulletin board (OASIS).

V B. The Capacity Market (kW)

Q. How is the post-1999 competitive market for capacity likely to operate within PJM?

A. The forces that will form the market for capacity are the disposition of the current surplus capacity (i.e., the forecasted load versus capacity and reserve requirements), the net cost to keep a plant in operation, and the cost to install new capacity. I expect that the bid price for capacity will reflect PJM's current surplus capacity status by remaining at or above the net cost of keeping capacity available for operation, but below the cost of incremental new capacity (combustion turbines or CT's) until after the turn of the century.[3] However, as the capacity surplus is depleted, the price of capacity could rise rapidly, creating the expectation that sustained high prices for capacity will be maintained.

Q. What will happen when capacity prices rise as the surplus is depleted?

A. Two forces will act to blunt the severity of anticipated capacity deficits and any corresponding increase in capacity price. These two forces are a planned increase in generation capacity and a reaction by buyers and sellers to the increased electricity price.

First, when expected revenues in the energy and capacity markets are high enough, generators who anticipate price increases will plan capacity additions. Since competitive markets do not restrict who can enter the generation market, new capacity will be planned by both incumbent generators and third-party generators new to PJM. Added capacity will work to relieve the growing capacity deficit within PJM.

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[3] The bid price will also reflect the revenue benefit, if any, of sales into the energy market.

Second, aggregators and power marketers will have every incentive to encourage customers, who will react to the higher electricity prices, to shift their purchases of firm load to lower-cost interruptible power. This restructuring of load within PJM ought to be efficiency-enhancing, as competitive forces bring actual customer requirements more in line with the electricity generation capabilities of the system. Any efficiency shift from the way electricity has been traditionally bought and sold toward alternative terms and conditions should delay the time when actual capacity additions are needed in PJM.

Q. How do power interchange agreements affect the price of capacity in PJM?

A. Power interchange agreements for imports of energy affect the price of capacity by reducing the marginal cost of electricity at any point in time. Absent the interchange agreements, higher cost facilities would have to be dispatched within PJM to meet the hourly load requirements of the system.

Second, interchange agreements affect the amount of capacity needed to be maintained within PJM for reliability purposes. While energy may be transacted across coordinated areas and PJM may even count out-of-region capacity to meet reserve requirements, there are limits to the amount of external capacity that may be counted towards system reserve requirements for reliability purposes.

Q. Will PJM's current reserve requirement be affected by the move toward retail competition in PJM?

A. Yes. Suppose that suppliers are load-serving entities ("LSE's") in PJM. Then, in accordance with Section 2809 of the Act, electric generation suppliers will be required by the Commission to ensure that the present quality of service does not deteriorate. Even so, PJM's current reserve requirement of 20% is likely to gradually be reduced as a result of the move toward competition. Competition will cause LSE's to search for ways to save costs. One of the obvious sources for cost-savings for LSE's will be the current reserve requirement. Many LSE's, responding to the demands created by customers and marketers, will have an incentive to reduce the reserve requirement. I expect that reliability standards will be re-examined and re-adjusted on a regular basis, that reserve requirements will ultimately reflect the expectations of customers.[4] Individual states and regional reliability councils will also be involved in setting reliability standards.

Considering all of these factors, I have used an 18% reserve requirement in my analysis.

Q. Are spot market transactions the only way capacity transactions take place in a competitive environment?

A. No. Bilateral capacity agreements are currently in place in PJM. I anticipate that the same sorts of suppliers and purchasers will remain within the system, so that short-term and long-term bilateral capacity contracts will continue to exist in PJM. However, I expect that forces of supply and demand will cause the price for capacity, as determined by these agreements, to closely approximate the competitive market, especially in the long run. For this reason, I have not separately modeled the bilateral capacity market.

VI THE METHOD USED TO ESTIMATE MARKET PRICES: THE EGEAS MODEL

Q. What method did you use to estimate market prices?

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[4] Discussions with PJM personnel indicated that the calculated PJM reserve requirement from the Association's reserve requirement studies has been reduced each year since 1992.

A. I directed personnel from my firm and from PP&L to use the Company's EGEAS (Economic Generation Expansion Analysis System) model to project market prices, using 1996 system data and forecasting through the year 2016.[5]

EGEAS is an economic dispatch model designed primarily for long-term system planning. As its name implies, the primary purpose of the model is to find the best possible combination of generation resources for meeting system load in the short run and in the long run. In the short run, EGEAS is a production cost model, dispatching units to meet demand levels in each hour of the year. Over the long run, the model adds capacity to the existing system to meet reliability constraints. Depending upon the economics at the point in time a new unit will be added, either peaking or combined-cycle technology is added to minimize cost.

Based on a variety of engineering and economic inputs associated with the cost and performance characteristics of the existing set of supply resources available to the system, EGEAS dispatches an electric power system -- in this case, PJM -- in the most

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[5] Mr. Schadt's testimony reports projected revenue data to the end of the book life of the plants. In most cases, that is beyond 2016. He has simply taken the last revenue data provided by me, using EGEAS to 2016, and escalated that data by the assumed rate of inflation from EGEAS.

economic manner. Output includes hourly (variable) costs for the marginal unit which, in turn, determines the market price of electricity in a competitive generation market.

EGEAS can calculate the market clearing price for a pre-specified set of units or for a least-cost expansion plan. I used the model in both modes. I used EGEAS to determine the least-cost expansion plan by selecting between a combustion turbine and a combined cycle unit. Every year the model selected which type of generation equipment was needed to meet load, including which, if any, were to be added to the mix in PJM. In this (dynamic capacity) mode, the model checks the need for additional capacity and brings on the most economically viable increment of new capacity. Additionally, within the model, reliability constraints eliminate combinations of generation resources with insufficient or over-abundant reserve capacity, energy, or LOLP (loss of load probability). The model also supports environmental and fuel-use constraints.

Q. What are the key variables used in EGEAS?

A. EGEAS dispatches units in a least-cost manner using a load duration curve approach. Two curves are generated, representing on-peak and off-peak periods for each month. Generation is then economically stacked according to its variable costs within these curves in compliance with PJM operating constraints. A utility's capacity is dispatched based on power pool economics and native load requirements.

To accomplish unit dispatch, EGEAS requires four categories of input data: fuel prices, engineering or unit data, load, and reserve constraints. For example, EGEAS requires that each facility be identified by fuel type. EGEAS also requires that fuel price escalators, like the ones shown in Exhibit STJ 3, be provided as an input along with the last actual fuel price. Along with generic unit data like loading strategy (base, intermediate, peaking) and whether the plant is designated for spinning reserve, EGEAS requires users to provide an escalation rate for operating costs, like variable O&M. The escalation rate used for variable O&M is shown in Exhibit STJ 4. Other unit data are the plant heat rate and block loading of the facility's capacity by heat rate, as well as the plant maintenance cycle (years). A summary of the key assumptions provided to EGEAS is shown in Exhibit STJ 5.

Q. Where did you get plant specific information like fuel costs and load data for non-PP&L facilities?

A. I used data and information provided to me by PP&L personnel. For the most part, these data are reported to PJM and made available to member companies. For example, the fuel related information can be found in 1996 "Allocation of Forecast Requirements" reports that each company files with the PJM Interconnection Association. This information was updated for PP&L facilities as late at November of last year. For non-PP&L facilities, fuel price data have been reviewed and, when necessary, updated by the Company's fuels department.

Q. How does EGEAS treat plant outages, reserve requirements and production costs?

A. Plant outages are modeled as planned and unplanned, to occur randomly, by unit.

A reserve requirement is specified in the model. On an hourly basis, EGEAS will compare peak load to available capacity in the system. If necessary, a "dynamic programming" module will add capacity based on the incremental cost of capacity. If the prevailing capacity price is insufficient to add a combined cycle unit, then a combustion turbine unit is added to the system.

EGEAS minimizes the production cost by using a merit order that reflects increasing total variable operating costs (i.e., fuel and O&M). The dispatch order can specify must-run units and units designated for spinning reserves (like PP&L's Montour facility). EGEAS then divides generating units into several blocks of capacity that are dispatched separately. Each block has a different heat rate, capacity (Mw) and block outage rate and as a result, a different variable cost. Variable O&M is assumed to be the same across blocks.

Q. Did you adjust the heat rates provided to you for PJM by PP&L?

A. No. Member companies provide PJM with heat rate information along with unit engineering data. Since these data are provided for PJM operating purposes, I saw no reason to adjust the data. EGEAS models a heat rate curve for blocks of generation using five different heat rate blocks. Having the option to use multiple heat rate blocks more closely approximates how a unit will perform under actual operating conditions.

Q. Does EGEAS take into account sales and purchases of electricity?

A. Yes. EGEAS allows the programmer to designate sales and purchases of power, like PP&L's sales contract with GPU, as an input to the model. These contracts are identified by size, cost ($/Mwh), type (e.g., on-peak purchase), contract duration, and so forth. In this way, the impact of power purchases and sales to other utilities and non-PJM regions are directly accounted for in the estimate of market price.

Q. What method was used to model unit availability?

A. EGEAS allows the programmer to designate unit availability. For this market price analysis, I set non-nuclear unit-availability factors at their actual average availability from the last five years. For nuclear units, I studied historical availability records (capacity factors) for nuclear plants in PJM and other systems. I concluded, that with one exception, PJM nuclear availability should be set at 78%, reflecting trends in historical data. I show the data used to calculate nuclear availability in Exhibit STJ 6.

Q. What was the exception to the historic capacity factors for nuclear plants in PJM?

A. I excluded Salem from the average. Its consistent history of low capacity factors would have, in my opinion, unfairly reduced the average capacity factor below that suggested by trends in the data from other nuclear plants. Hence, while Salem's historically low capacity factor was prevented from unfairly reducing the expected average availability of nuclear capacity, Salem's capacity is included in EGEAS at the 78% capacity factor applied to all nuclear plants in PJM.

Q. How does EGEAS estimate the market price of electricity?

A. Using the inputs I provided to the model and the capacity expansion plan that EGEAS identified as most viable under these economic assumptions, the model calculates the hourly market clearing price for PJM. The market clearing price is the incremental cost of the last unit dispatched within PJM for each hour. Those market clearing prices are listed in Exhibit STJ 7.

Q. In your estimate of competitive market prices, do you include compensation for start-up and no-load costs?

A. Yes, in part. Generating companies will require compensation for these additional costs. I capture no-load costs in EGEAS through the multi-block heat rates which account for no-load costs. EGEAS does not have the ability to model start-up costs. However, when compared to energy costs, start-up costs are a small part of the cost of energy. Hence, start-up costs are not likely to impact plant dispatch in any way that will significantly affect stranded cost estimates.

In calculating PP&L's stranded costs, any increase in the market price of energy due to start-up costs is not accounted for in PP&L's revenues. Similarly, these costs are not accounted for on the cost side of the analysis. Start-up costs do not enter into the stranded cost estimate on either side of the ledger.

Q. As part of your market price analysis, do you expect generating units to realize revenue from other market products, such as spinning reserve or other ancillary services?

A. Yes. However, as noted by PP&L's Mr. Whitehead, transmission service will include all ancillary services defined by the FERC in Order No. 888. I have, however, accounted for revenue from spinning reserves in my estimate of market price.

Q. How do you capture revenue for spinning reserves?

A. First of all, EGEAS is set using the same assumptions for spinning reserves as provided to PJM by its member companies. EGEAS identifies those units that will provide enough spinning reserve to equal the largest unit on the system. Second, economic dispatch of units in EGEAS takes into account plants with spinning reserves. EGEAS loads the first blocks of spinning reserve before adding other blocks of capacity from other units. Because EGEAS gives priority to spinning reserve, the variable cost of these blocks of energy will impact energy price. The capacity price is not directly affected by spinning reserve.

Q. What are the resulting market prices for power and capacity in PJM?

A. The prices shown in Exhibit STJ 7 are annual average market-clearing energy prices for PJM.

Q. The market prices that you are sponsoring on behalf of PP&L are lower than those sponsored by PECO witnesses in that company's recent "Application of PECO Energy Company for Issuance of a Qualified Rate Order", January 22, 1997. Why?

A. As I have explained, my estimates of market prices were derived from the incremental cost, as estimated by EGEAS, needed to serve the demand for electricity on an hourly basis throughout the system. These are the market-clearing prices facing buyers and sellers of electric power throughout PJM, including imports and exports.

The market values or prices supplied by PECO's witnesses do not represent a single market-wide price at any point in time that reflects the pressures of buyers and sellers for both energy and capacity in PJM (as affected by imports/exports of energy). Instead, PECO's witnesses reported the per Mwh price needed to dispatch PECO's facilities, on average, for that year.

PECO's witnesses testified that they provided "the realized market price of PECO units"[6] and the "revenues per Mwh generated" by PECO facilities.[7] These are not the same as the market prices I generated. The prices shown in Exhibit STJ 7 would clear the regional market on an hourly basis, including hours in which PP&L's facilities are not dispatched. Unseen in any of PECO's analysis are the prices for energy during the hours that PECO's plants are not being

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[6] PECO Statement No. 8, Direct Testimony of B.S. Venkateshwara, Application of PECO Energy Company for Issuance of a Qualified Rate Order, p. 8, lines 24-25.
[7] PECO Statement No. 9, Direct Testimony of W.H. Hieronymous, Application of PECO Energy Company for Issuance of a Qualified Rate Order, p. 3, line 13.

dispatched by PJM. Average annual market prices have to include both the observations sufficiently high enough to dispatch PECO's generation facilities and those that were too low to call up 100% of a PECO plant.

Q. Does this mean PECO's revenue by plant analysis is wrong?

A. No. When asked to determine the revenue each plant produces each year, PECO appears to do the arithmetic correctly to get plant cash flows, but this is not the market clearing price. It would be more accurate to say that PECO's figures represent the market value of its own generating units, not market price.

VII INPUT VARIABLES: SOURCES AND ASSUMPTIONS

Q. You have relied on forecasts of a number of variables to produce your estimates for market clearing prices in PJM. Can you explain why you chose to forecast variables rather than assume 1996 values for these variables would prevail throughout the transition period?

A. Yes. There are a number of good reasons why I chose to forecast key input variables, like fuel prices and O&M, rather than do something simple like using today's energy and capacity prices in EGEAS for the next twenty years. Market forces are dynamic, not static. As a result, economists must deal with variables like prices and costs that change, rather than stay the same over time.

Fixing future electricity prices, at their last known value, implies that market forces are going to come together over the forecast time horizon like they did in 1996. A simple examination of the movement in key variables, like fuel and O&M, indicates that market forces are causing certain variables to change at different rates and in different directions over time.

Second, in many cases, it is possible to identify trends in historic data that appear to be moving in a predictable direction and at a predictable rate. Good examples are recent changes in the annual rate of inflation and the annual change in economic growth.

Third, secular change in key factors such as the introduction of competition, or a change in the regulatory environment, have predictable impacts on variables. For example, economic theory is clear about the tendency toward lower prices in markets that evolve from more to less monopoly power, as market efficiency is enhanced and costs reduced due to competitive pressures.

For all of these reasons, attempts to forecast prices by forecasting the key variables that contribute to price formation is an improvement on simply assuming that variables do not change over the forecast horizon, or that all variables change in similar ways in the future.

Q. How do you respond to critics of energy price forecasts that say predicted values are never accurate and are biased upward?

A. The critics are right with regard to the general issue of accuracy and forecast bias since 1973, and wrong with regard to the implication that forecasting has failed to add value since the first energy crisis. In 1973, 1980 and again in 1986, American consumers and the oil industry sat on the precipice of the unknown. The world's largest market was shocked by major price dislocations that threatened everything from national security to household budgets. Granted, the long-term forecasts that emerged during the weeks and months following these shocks were varied and (eventually) found to be inaccurate; yet forecasting added structure and discipline to a process when consumers, the business community and politicians demanded expert opinion.

Q. How do you use forecast information?

A. As I stated earlier, I am more comfortable relying, whenever possible, on a combination of forecasts (consensus view). In this way, I can observe how a number of organizations think key variables will change and how those changes are likely to impact a competitive market for electricity.

VII A. Energy Prices

Q. Can you provide a brief explanation of the data sources and assumptions that underlie the price forecast in Exhibit STJ 7?

A. Yes. I will take them in turn beginning with the assumption and data sources for the fuel price projections.

I have a long history forecasting fuel prices. I used and developed forecasting models and evaluated industry data for oil, gas and coal as early as 1975 and extensively beginning with my assignments with ARCO. In 1986, I joined Chase Econometrics, the nation's second largest economic/industry forecasting firm. I was a member of the firm's senior management in charge of most of the industry groups, including energy. I am very familiar with the way firms like Data Resources, Inc. ("DRI"), WEFA and the Gas Research Institute ("GRI") forecast energy prices. I am also familiar with the models, methods and data used by the Energy Information Administration ("EIA") and the International Energy Agency ("IEA"). My knowledge of energy forecasting methods leads me to review a number of forecasts, not just one forecast, when arriving at a view of energy price trends.

Additionally, I examined the recent historical record for price behavior in assessing the short-to-intermediate term forecasts of others. In that regard, I have examined forecasts from the following sources in producing the outlook for fuel oil, natural gas and coal escalation rates found in Exhibit STJ 3: DRI; WEFA; GRI; American Gas Association ("AGA"); EIA; IEA; State of Alaska; Oil & Gas Journal ("O&GJ"); Society of Professional Petroleum Engineers ("SPEE"); Enron Corporation; British Petroleum; Coal Outlook; and others. Whenever possible, I looked at the explanation of the variables underlying the organization's forecast, such as predictions about economic growth, OPEC production, regulatory trends, reserve additions, and transportation costs.

As a result, the outlook in Exhibit STJ 3 for fuel oil, natural gas and coal, delivered to utilities, is compiled from a large body of data, and in my view, represents a reasonable consensus forecast of fuel prices.

Q. Did you perform a similar analysis to develop your view about inflation?

A. Yes. In recent years, the rate of inflation has been steady, fluctuating annually in a relatively narrow range. Inflation rates since 1992 reflect the Federal Reserve's efforts to control the money supply and an improved competitive environment for U.S. businesses. Hence, despite the fact that the current economic expansion is six years old, there is little evidence that inflation is likely to return to levels seen in the 1980's.

For purposes of estimating market prices for electricity or stranded costs, I am not assuming that a recession impacts the U.S. economy. This is a conservative assumption from the point of view of estimating stranded cost since a recession would reduce electricity demand and spot electricity prices compared to continued economic growth. Therefore, I have adopted a steady 2.5% inflation rate for the economy throughout the forecast horizon.

Q. What assumptions have you incorporated into your forecast of variable O&M?

A. My view of future changes in variable O&M costs, as shown in Exhibit STJ 4, stems from three sources of data. First, an examination of the trends in O&M costs in capital intensive industries beginning with the 1980's suggests that periods of competitive change often cause internal cost escalation rates in variable O&M to decline, at least in real terms. For example, a recent article on the highly-competitive (and partially regulated) oil refining industry, cited data showing O&M costs declining as much as 10-15 percent per year over the last several years.[8]

Second, the recent restructuring that has taken place in the natural gas pipeline industry caused variable O&M costs to trail inflation. Following FERC Order No. 636, pipeline company restructuring produced firms that were encouraged to respond to competitive pressures, and firms that encouraged the introduction of cost-saving technology. Third, evidence and opinion from various industry and academic publications suggest that variable O&M costs in

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[8] Anne Rhodes, "Hostile Operating Climate Augurs Further Closures for U.S. Refiners," *Oil & Gas Journal*, March 10, 1997, 21-23.

parts of the industry may be rising slower than inflation for some time. Evidence from these three categories of information led me to use an escalation of 1.5% (negative one percent real price escalation) through the year 2000, and 2.5% (flat real price escalation) thereafter.

Q. What assumption and sources of information have you used to establish the escalation in emissions allowance prices for SO_2?

A. EGEAS allows the user to input an escalation rate for emissions allowances by adjusting the fuel price escalators. The first step is to identify which units will be running when the region is not in compliance. EGEAS accomplishes this by checking the emission production rate against the annual emission limit input for each facility. Once the units are identified, then those units that are subject to emissions limits are assigned allowances sufficient to bring them into compliance. The cost of bringing those units into compliance is built into the fuel escalation rates for PJM.

There has been a steady decline in the cost of SO_2 allowances over the past several years, with a modest increase in recent months. Expert opinion varies with regard to a "consensus" forecast of allowance prices, like all other forecasts. One such forecast, prepared by ICF Kaiser, estimates allowance prices under various assumptions.[9] In my view, recent trends in allowance costs more closely approximate the ICF "low case" from this 1996 study. This view was reinforced by industry publications and conversations I have had with environmental economists and emissions experts at both Harvard University and the Massachusetts Institute of Technology.

Based on the information and data gathered from a variety of sources, I assigned EGEAS an initial SO_2 allowance cost consistent with that found in the ICF Kaiser study (low case) through 2000. After that, the allowance costs were escalated with inflation (2.5% per annum).

NO_x emission allowance costs are too uncertain and allowance markets are still too thin to form reliable estimates of current price levels or future rates of change in this variable. The market for these allowances will be driven by the cost of the equipment used to reduce NO_x emissions. A survey of the literature and academic experts convinced me that industry has not established a credible technique for estimating the future market value for these allowances. Further, when cost-based estimates are provided, the apparent impact on the

[9] ICF Kaiser, "The Potential Market Value of SO_2 Allowances," June 1996.

PJM market-clearing price would be so small as to be almost undetectable. Hence, NO_x emission allowance costs are excluded in the forecast of future market prices for electricity.

Q. What assumption and data source was used for EGEAS regarding plant mix and availability?

A. Plant mix and availability data were provided by PP&L staff for the Company's facilities. For non-PP&L generation plants, estimates of availability and plant type are based on PP&L operating experience, marketing efforts, and reports filed by other utilities with PJM as required by the power pool.

Q. What was the source of the electricity demand forecast used in EGEAS?

A. Rather than forecast electricity demand for PJM and PP&L, I relied on personnel from PP&L to supply me with PJM documents showing forecasted electricity demand and with updates of PP&L's estimates of its electricity demand. For example, PP&L updated its forecast for electricity demand as late as December 1996[10].

[10] PJM, "Allocation of Forecast Requirements," updated December 7, 1996.

Q. What heat rate does EGEAS use for capacity additions in the model?

A. The assumed heat rates are 10,200 BTU/kwh for a combustion turbine unit and 7,000 BTU/kwh for a combined cycle unit. PP&L provided these data to me based on information from vendors. These data are consistent with other heat rate assumptions that I am aware of in other recent industry studies.

VII B. Capacity Prices

Q. What capacity prices were used to derive the market price of electricity in PJM?

A. The capacity prices are shown in Exhibit STJ 8. These forecast values are based in part on PP&L's energy marketers' experience negotiating with buyers of the Company's capacity. PP&L is a net seller of capacity, both in the short-term (spot) market and in the forward market. Hence, PP&L has data based on actual transactions.

Second, my forecast for capacity prices recognizes that competitive markets tend to exhibit a rapid increase in spot prices as a potential shortage builds. It is this increase in price that brings on new capacity and creates the environment where marketers may succeed in shifting the utility's electricity customers off firm load to the marketers less costly interruptible loads. However, the "peakedness" of any price increase into the early part of the next century will be tempered by the impact of a shift from a regulated to a competitive environment as a result of restructuring of the industry. Economists know from the deregulation of other industries, such as airlines, railroads and most recently natural gas, that persistent price softness can be sustained for several years at market prices below that needed to bring on new capacity (long run marginal cost).

Economic theory holds that prices will tend toward short-run marginal cost (SRMC) in competitive markets, sending efficient signals to markets for production, consumption and investment.[11] However, the anticipated entry of new generation sources to PJM, in the form of marketers, aggregators and other utilities, will exert added competitive pressure on existing utilities to supply power at lower energy prices. These new competitive pressures will require disciplined cost-saving

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[11] In general, pricing on the basis of SRMC results in different prices and quantities than prevailing long-run marginal or average cost. When prices are equal to long-run marginal cost (LRMC), they reflect not only short-run variable costs, but capital costs as well. Alfred E. Kahn, The Economics of Regulation (1993), pp. 88-89 and 174.

by utilities and the rapid adoption of efficiency enhancing operation and management techniques.

Q. How are assumed summer and winter loads used in the peak day analysis for EGEAS?

A. The peak day analysis was performed as part of the load shape provided by PP&L for use in EGEAS. Summer and winter peaks help to determine the load shape. The load projections are consistent with those accepted by PJM as part of the most recent planning exercise.

VIII REVENUE BY PLANT

Q. What method did you use to convert the market price information to revenue by plant information?

A. The revenue by plant information was generated in two basic steps: revenue by plant for capacity and revenue by plant for energy.

Q. Please explain how you calculate capacity revenue by plant.

A. PP&L provided me with the (summer) capacity by plant (Mw). The data were combined with the (annual average) capacity price shown for PJM in Exhibit STJ 8 to produce a capacity revenue stream for each year of the forecast. In this way, I have implicitly assumed that even with competitive market pricing, PP&L will receive capacity revenue for the full year from each available plant, with revenues based on the incremental cost of that capacity.

Q. What do you do with the capacity revenue by plant data?

A. I provide PP&L Witness Mr. Schadt with that information. Mr. Schadt's Exhibit JRS 1 includes that data in his stranded cost evaluation for each plant. It appears in his plant by plant summary sheets titled "Stranded Evaluation" under the heading "Revenues" near the bottom of each of those summary sheets.

Q. Please explain how you calculate energy revenue by plant.

A. The energy revenue calculation requires several inter-related steps. Some of the steps are needed to decompose the average price of energy into corresponding peak, intermediate and base load prices. The rest of the calculations focus on the distribution of the number of hours a plant was dispatched during the year into peak, intermediate and base load.

Q. Please explain the steps necessary to determine peak, intermediate and base load prices for each plant.

A. First, I collected the annual capacity factor for each plant from EGEAS. I also collected the annual hourly system load requirements. In addition, I collected the hourly market clearing price for each hour's system load.

Second, I arranged the annual hourly system load requirements from highest to lowest. I then divided this group of hourly system load requirement data as follows: the highest 10% into peak load, the next highest 30% into intermediate load, and the remaining 60% into base load. In this way, each year's system load is allocated into peak, intermediate and base load categories.

The third step is to identify the price for each of these hourly loads and array those prices in the same manner. However, since stranded cost calculations only need one price for peak, intermediate and base load, I averaged the individual prices in each group to create peak, intermediate and base load prices for that period. These are the prices that were used to produce the individual annual plant revenue data that are part of PP&L Witness Schadt's stranded cost calculations.

Q. Where does Mr. Schadt get the generation data, by plant, that can be used with the price data to produce plant revenues?

A. The method for determining hourly generation by plant is also conducted in several steps.

I start by taking the annual plant capacity factor data from EGEAS and distribute generation into peak, intermediate and base load depending on the hours the plant was dispatched during the year.

For example, suppose EGEAS indicates that market conditions determined one plant's capacity factor to be 15%. That means the plant was dispatched about 1300 hours during the year (0.15/yr. * 8760 hr./yr.).

I turned to PP&L for a standard I could use to determine how many of this plant's 1300 hours should be allocated to peak, intermediate or base load. PP&L sets its plants' equivalent availability factor at 80% (hours that the plant is available).[12] That means PP&L expects that their plants would be available to operate (8760 hours per year * 0.8/yr.), or about 7000 hours. Plants like Montour actually

[12] Actual operation of a facility is captured by EGEAS' estimated capacity factors while the equivalent availability estimate is the standard used by PP&L.

operate (as measured by Montour's annual capacity factor) near the 80% level, while plants like Martin's Creek 3 & 4 operate at much lower levels, nearer to 15%.[13]

The next step is to divide the plant's hourly annual generation (hours the plant was running) into peak, intermediate and base load, assuming that the plant's availability is spread evenly over the loads. For example, 10% of 7000 hours is 700 hours, 30% of 7000 hours is 2100 hours, and so forth.

Hence, for 700 of the plant's 1300 hours of annual operation, the plant should be credited with the peak price taken from the data I provided above. The remaining 600 hours would receive the price for intermediate load. This plant was not in operation enough of the year to warrant base load prices.

I repeat this method for each of PP&L's plants, then provide the data to Mr. Schadt. Those results appear under "Revenue" in each of Mr. Schadt's plant level "Stranded Evaluation" sheets in Exhibit JRS 1.

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[13] Susquehanna's equivalent available factor was set equal to its capacity factor at 78%. Hence, when Susquehanna was *available*, *it was running*.

Q. What other data do you supply that is used in Mr. Schadt's estimates of stranded cost on a plant-by-plant basis?

A. Each of Mr. Schadt's plant level "Stranded Evaluation" sheets lists five lines under "Revenues". I supply the data for each of those five lines. Hence, in addition to the energy and capacity revenue entries noted above, the market clearing price of generation (MCPG) entry is derived by dividing "Total Revenues" (energy plus capacity) by "Generation".

Q. Does this conclude your prepared direct testimony?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 8

Direct Testimony of Joseph R. Schadt

Q. Please state your full name and business address.

A. Joseph R. Schadt, Two North Ninth Street, Allentown, Pennsylvania, 18101

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

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") as Manager-Financial Support Services in the Company's Financial Department.

Q. Please describe your educational background and employment history.

A. I received a Bachelor's Degree in Accounting from Wake Forest University in May 1979. Upon graduation, I worked for Duke Power Company for two years in its Accounting Systems and Forecasting departments. In July 1981, I began working for PP&L.

Q. Please describe your employment history with the Company.

A. I began my employment with the Company as an Accountant in the General Accounting Department and remained there for four years, progressing to the position of Senior Accountant. In General Accounting, I participated in the maintenance and closing of the Company's books and records and had primary responsibility for the calculation of the actual cost components of the Energy Cost Rate, unbilled revenues and the miscellaneous billing function. Subsequently, I transferred to the Financial Reporting Department where I remained for nine years. I was promoted to Accounting Analyst in Financial Reporting and my responsibilities included the completion and filing of the Company's Annual Report to Shareowners, Forms 10-Q and 10-K for the Securities and Exchange Commission and FERC Form 1. Through my experience in General Accounting and Financial Reporting, I was able to develop a thorough knowledge of accounting and reporting concepts applicable to the electric utility industry in general and PP&L in particular. In November 1994, I was promoted to the position of Supervisor--Accounting Research. In this position, I had primary responsibility for developing the Company's position on open accounting issues applicable to the industry. In addition, I was significantly involved in special projects, such as transmission access and other deregulation issues. In February 1996, I was promoted to my current position, Manager--Financial Support Services. In this position, I have primary responsibility for the Company's financial forecasting, budgeting and business planning functions. Additionally, my department continues to have primary responsibility for accounting research and the analysis of the financial implications due to the deregulation of the generation portion of the electric utility industry.

Q. Please describe any memberships in professional or industry associations.

A. I am currently a member of the Accounting Standards Committee and the Nuclear Decommissioning task force of the Edison Electric Institute.

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

A. My testimony and accompanying exhibit describe and support the Company's calculation of "stranded costs" as provided for in the Electricity Generation Customer Choice and Competition Act (the "Act").

Q. Are you responsible for any of the Company's responses to the Commission's filing guidelines submitted in Exhibit 2?

A. Yes. Under the caption entitled Restructuring Issues, I am responsible for the following guidelines: RP-D.5., G.4., L.1., L.2., L.3., L.4., L.5., L.7., L.8., L.10., L.11., and L.17.

Q. Please summarize your testimony.

A. Applying the definition of transition or stranded costs set forth in the Act, PP&L's stranded costs at January 1, 1999 before mitigation equal $5.6 billion. Future initiatives to mitigate stranded costs are described in Mr. Hill's testimony and reduce PP&L's stranded costs at January 1, 1999 to $4.6 billion.

Q. What costs are included in the Company's claim?

A. As provided for in the Act, the Company's claim is comprised of (1) regulatory assets and other deferred charges typically recoverable under traditional regulation, and cost obligations under Commission-approved contracts with non-utility generators ("NUGs"); (2) prudently-incurred costs related to cancellation, buyout, buydown or renegotiation of NUG contracts and (3) net plant investments and operating costs associated with existing generation plants and facilities, disposal of spent nuclear fuel, decommissioning costs associated with existing generating plants, and other transition costs, including severance, early retirement, outplacement and related costs for employees who are affected by changes that are expected to occur as a result of the restructuring of the electric utility industry pursuant to the Act.

I have segregated the calculation of PP&L's stranded costs into the following four areas:

- Nuclear generation
- Fossil generation
- NUGs
- Generation-related regulatory assets

The fossil category includes the Company's coal-fired, oil-fired, hydroelectric, combustion turbine and diesel generating facilities.

Q. Please describe the Company's methodology for determining stranded costs.

A. As explained in the Act, stranded costs are the present value of net generation-related costs that would be recoverable under traditional regulation but may not be recoverable in a competitive market and that remain after mitigation efforts. The methodology for calculating nuclear generation plant and fossil generation plant stranded costs compares the annual revenue requirements for each generating plant to the projected annual revenues each plant would receive from the sale of its output using market-based prices for each year beginning January 1, 1999 to the end of its remaining service life. A PUC jurisdictional percentage was applied to the annual excess or deficiency. The calculation of the PUC jurisdictional percentage is explained in Mr. Kleha's testimony and exhibits. The resulting stream of annual excesses or deficiencies was discounted to present value. This present value figure is the PUC jurisdictional amount of stranded costs for nuclear generating plants and fossil generating plants.

For NUGs, I compared the expected annual cost of the output that PP&L is required to purchase under each NUG contract from January 1, 1999 through the end of the initial contract term to the annual revenues from the sale of such output using market-based prices. To the resulting deficiency, I added the annual payments to be paid after December 31, 1998 for two NUG buyouts recently negotiated by the Company. A PUC jurisdictional percentage was applied to the total annual deficiency. The resulting stream of annual deficiencies was discounted to present value. This present value figure is the PUC jurisdictional amount of stranded costs for NUGs.

For generation-related regulatory assets, I determined the annual amortization that would be charged to expense beginning January 1, 1999 under traditional cost-based regulation. A PUC jurisdictional percentage was applied to the amortization. The resulting stream of annual amortizations was discounted to present value. This present value figure is the PUC jurisdictional amount of stranded costs for generation-related regulatory assets.

Q. Have you prepared an exhibit setting forth the results of the Company's stranded costs?

A. Yes. Exhibit JRS 1 shows the stranded costs by the four categories I previously identified: nuclear generation, fossil generation, non-utility generation, and regulatory assets. It includes detailed calculations by plant, by NUG, and by generation-related regulatory asset. For each category, I compared the revenue requirements to competitive market revenues. The Economics Resources Group, Inc. ("ERG") calculated the market revenues, which include components for energy and capacity. See PP&L's response to the Commission's filing guidelines at Appendix A, Section L, Item 9 for detailed information regarding market revenues.

Nuclear Generation

Q. Please describe in more detail the calculation of the annual revenue requirements for nuclear generation.

A. The annual revenue requirements for nuclear generation include the following cost components:

- Return on investment
- Income taxes associated with the return on investment
- Depreciation
- Fuel expense
- Operation and maintenance expense
- Decommissioning costs
- Taxes other than income

A summary of the annual revenue requirements for nuclear generation is provided in Tab C of Exhibit JRS 1.

Return on Investment

I calculated the return on investment for each year beginning January 1, 1999 to the end of the generating units' lives by multiplying the Company's nuclear rate base by the Company's weighted cost of capital at December 31, 1996. Details of the weighted cost of capital are provided in Tab A of Exhibit JRS 1. Capital structure and the embedded cost of debt and preferred stock were supplied by the Company's Financial Department. The cost of equity (11.5%) is the allowance in the Company's most recent base rate case at Docket No. R-00943271 and is discussed in the testimony of Mr. Moul.

Nuclear rate base includes the net book value of nuclear generation plant, capitalized software costs related to nuclear operations included in intangible plant, an allocated portion of general plant supporting nuclear generation, nuclear plant materials and supplies inventory, and prepayments applicable to nuclear generation operations less accumulated deferred income taxes applicable to nuclear generation plant.

The starting point for the calculation is the net book value of the Company's nuclear generation plant, intangible plant and general plant at December 31, 1996, derived from the Company's books and records. Net book value was reduced to reflect a reclassification of the nuclear depreciation reserve from transmission and distribution depreciation reserves, which is one of the Company's mitigation strategies. Budgeted capital additions for 1997 were provided by the Company's Nuclear Department and future capital additions were projected by escalating 1997 budgeted additions by 2.5%. According to the Nuclear Department, the 1997 budgeted additions are representative of annual amounts needed to operate properly and maintain the Susquehanna plant. The escalation factor of 2.5% is an estimate of the average long-term inflation rate and was provided by ERG. Depreciation is described more fully below, but essentially is calculated using straight-line depreciation over the remaining life of the plant (the book lives end on July 17, 2022 for Unit 1 and March 23, 2024 for Unit 2), plus, in 1997 and 1998, the additional depreciation related to the modified sinking fund method of depreciation, which converts to straight-line depreciation in 1999. The accumulated deferred income taxes applicable to nuclear generation were projected as of the end of each year. The amount of prepayments related to nuclear operations and material and supplies inventory was calculated by taking the average balance for the 13-month period ended December 31, 1996 and escalating that amount at a 2.5% rate for the remaining life of the plant.

In summary, the Company's nuclear rate base at the end of each year is the sum of the net book value of nuclear generation plant, computer software used in nuclear generation and included in intangible plant, an allocated portion of general plant, nuclear plant materials and supplies inventory, and prepayments applicable to nuclear generation operations less accumulated deferred income taxes applicable to nuclear generation plant

Income Taxes Associated with the Return on Investment

In contrast to the other items of revenue discussed herein, there is no corresponding item of expense deductible for income tax purposes for the return on equity capital. To ensure that the equity investors receive the after-tax return on their investment, I grossed up the revenue requirement for Federal and State income taxes payable on the return. I calculated the amount of the "gross up" using the following formula:

$$\text{Gross Up} = \frac{\text{After-Tax Return on Equity Capital}}{(1 \text{ minus Effective Income Tax Rate})} \text{ minus After-Tax Return on Equity Capital}$$

The Effective Income Tax Rate is 41.4935%, calculated as follows:

Statuatory Federal tax rate	35.0000%
Statuatory State tax rate	9.9900%
Less: Impact of State tax deduction for Federal taxes	-3.4965%
Effective income tax rate	41.4935%

In accordance with Federal income tax law, the PUC allowed the Company to return the benefit of the Federal investment tax credit to ratepayers ratably over the life of the assets that generated the credit.

Therefore, total income taxes were reduced by the amortization of investment tax credits applicable to nuclear generation. The amortization of investment tax credits uses the straight-line methodology over the lives of the related assets.

Depreciation

Depreciation represents the return to the Company of its investment in nuclear generation facilities and, beginning January 1, 1999, is calculated using the straight-line depreciation methodology over the lives of the generating units (the scheduled retirement dates are July 17, 2022 for Unit 1 and March 23, 2024 for Unit 2). The effect of the reserve reclassification is not reflected in the depreciation basis; this effectively mitigates nuclear stranded costs by $317 million. Depreciation also includes the depreciation of the Company's general plant allocated to nuclear generation and the depreciation of computer software included in intangible plant. Depreciation of general plant is calculated using the straight-line methodology over the book life, through June 30, 2044, and computer software included in intangible plant is depreciated on a straight-line method over five years. All capital additions are assumed to be placed in service in the middle of the year; accordingly, one-half year of depreciation is calculated on each year's capital additions.

Fuel Expense

I obtained projected nuclear fuel costs for the Susquehanna plant from the Company's Nuclear Department. Fuel expense is calculated by multiplying a mills/kwh rate by the expected kwh output. Expected kwh output is calculated using a 78% capacity factor, which is the average actual capacity factor for 1993-1996 and is representative of the capacity factor the Nuclear Department believes will be attained in the future.

Operation and Maintenance Expense

I obtained annual projected operation and maintenance expenses for the Susquehanna plant from the Company's Nuclear Department. These expenses include payroll taxes and employee benefits. The annual projected operation and maintenance expenses were derived by escalating 1997 budgeted operation and maintenance expenses at the rate of 2.5%. I projected annual administrative and general costs of the Company and allocated a portion to nuclear generation (see Mr. Kleha's testimony and exhibits for an explanation of allocation factors). Through 2001, administrative and general costs are projected to decline as the Company re-engineers its processes in preparation for competition. Beginning in 2002, administrative and general costs escalate at a 2.5% annual rate.

Nuclear Decommissioning

I included in annual nuclear decommissioning expense the amount that the Company is recovering in its existing retail and wholesale rates and then adjusted revenue requirements to the applicable PUC jurisdictional portion.

Taxes Other Than Income

I calculated the annual expense for taxes other than income. Taxes other than income applicable to nuclear generation include an allocated portion of the Company's expense for Pennsylvania capital stock tax and Pennsylvania public utility realty tax. I escalated these taxes at a rate of 2.5% for the remaining lives of the nuclear generating units.

Fossil Generation

Q. Please describe in more detail the calculation of the annual revenue requirements for fossil generation.

A. The methodology is essentially the same as the methodology used for nuclear generation. The annual revenue requirements for fossil generation include the following cost components:

- Return on investment
- *Income taxes associated with the return on investment*
- Depreciation
- Fuel expense
- Operation and maintenance expense
- Decommissioning costs
- Taxes other than income

A summary of the annual revenue requirements for fossil generation is provided in Tab D of Exhibit JRS 1.

Return On Investment

I calculated the return on investment for each year beginning January 1, 1999 to the end of the life of each fossil, hydroelectric, combustion turbine and diesel generating plant (fossil plants) by multiplying the Company's fossil rate base by the Company's weighted cost of capital at December 31, 1996. Details of the weighted cost of capital are provided in Tab A of Exhibit JRS 1. Capital structure and the embedded cost of debt and preferred stock were supplied by the Company's Financial Department. The cost of equity (11.5%) is the allowance in the Company's most recent base rate case at Docket No. R-00943271 and is discussed in the testimony of Mr. Moul.

Fossil rate base includes the net book value of fossil generation plant, an allocation portion of general plant supporting fossil generation, fossil plant fuel inventory, materials and supplies inventory, and prepayments applicable to fossil plant generation operations less accumulated deferred income taxes applicable to fossil generation plant.

The starting point for the calculation is the net book value of the Company's fossil generation plant and general plant at December 31, 1996, derived from the Company's books and records. Projected capital additions are detailed in PP&L's five-year construction budget for 1997-2001, with minor adjustments to reflect updated information provided by the Power Production and Engineering Department. For example, clean air compliance costs in the 1997-2001 construction budget exclude costs for Selective Catalytic Reduction (SCR) to better reflect current compliance strategies. Beyond 2001, capital additions have been forecast on an individual plant basis through their remaining book lives by the Power Production and Engineering Department. Depreciation is described more fully below but essentially is calculated using straight-line depreciation over the remaining life of the plants. The accumulated deferred income taxes applicable to fossil plant generation were projected as of the end of each year. The amount of prepayments related to fossil plant operations and fuel and material and supplies inventory was calculated by taking the average balance for the 13-month period ended December 31, 1996 and escalating that amount at a 2.5% rate for the remaining lives of the plants.

In summary, the Company's fossil rate base at the end of each year is the sum of the net book value of fossil generating plant, and allocated portion of general plant, fossil plant fuel and materials and supplies inventory, and prepayments applicable to fossil generation operations less accumulated deferred income taxes applicable to fossil generation plant.

<u>Income Taxes Associated with the Return on Investment</u>

In contrast to the other items of revenue discussed herein, there is no corresponding item of expense deductible for income tax purposes for the return on equity capital. To ensure that the equity investors receive the after-tax return on their investment, I grossed up the revenue requirement for Federal and State income taxes payable on the return. I calculated the amount of the "gross up" using the following formula:

$$\text{Gross Up} = \frac{\text{After-Tax Return on Equity Capital}}{\text{(1 minus Effective Income Tax Rate)}} \text{ minus } \text{After-Tax Return on Equity Capital}$$

The Effective Income Tax Rate is 41.4935%, calculated as follows:

Statutory Federal tax rate	35.0000%
Statutory State tax rate	9.9900%
Less: Impact of State tax deduction for Federal taxes	-3.4965%
Effective income tax rate	41.4935%

In accordance with Federal income tax law, the PUC allowed the Company to return the benefit of the Federal investment tax credit to ratepayers ratably over the life of the assets that generated the credit.

Therefore, total income taxes were reduced by the amortization of investment tax credits applicable to nuclear generation. The amortization of investment tax credits uses the straight-line methodology over the lives of the related assets.

Depreciation

Depreciation represents the return to the Company of its investment in fossil generation facilities and is calculated using the straight-line depreciation methodology over the lives of the generating plants. Depreciation also includes the depreciation of the Company's general plant allocated to fossil generation. Depreciation of general plant is calculated using the straight-line methodology over the book life, through June 30, 2044. All capital additions are assumed to be placed in service in the middle of the year; accordingly, one-half year of depreciation is calculated on each year's capital additions.

Fuel Expense

The Power System Support Department, in cooperation with ERG, used the Electric Generation Expansion Analysis System (EGEAS) to model the Pennsylvania-New Jersey-Maryland power pool operations over time. Outputs from the EGEAS model include the estimated amount of energy that each plant within PJM will produce, fuel costs, and each plant's projected capacity factor. See PP&L's response to the Commission's filing guideline at Appendix A, Section L, Item 9 for detailed information about the outputs of the EGEAS model.

Operation and Maintenance Expense

I obtained annual projected operation and maintenance expenses from the Company's Power Production and Engineering Department. These expenses include payroll taxes and employee benefits. For 1997 through 2001, the Company has an operation and maintenance plan, which reflects specific costs designed to achieve certain availability goals. Beyond that time frame, direct operation and maintenance costs are escalated at the rate of 2.5%, with certain adjustments. For example, in 2004, operation and maintenance costs are increased to reflect the installation of additional equipment to comply with clean air requirements. Other minor adjustments to reflect timing differences between plant outages also are incorporated. In addition, operation and maintenance costs are projected to begin to decline in the two years before a plant is retired. Because all plants are projected to retire on June 30 of their retirement year, operation and maintenance costs in that final year are one-half the annual level. I calculated the projected annual administrative and general costs of the

Company and allocated a portion to fossil generation (see Mr. Kleha's testimony and exhibits for an explanation of allocation factors). Through 2001, these costs are projected to decline as the Company as it prepares for competition. Beginning in 2002, administrative and general costs are calculated to escalate at a 2.5% rate.

Fossil Plant Decommissioning

I included the projected cost of decommissioning for each coal-fired and oil-fired generating plant beginning in the last year of the plant's remaining life. The decommissioning activities are projected over a 3-year period. Consequently, 40% of the projected cost is included in the last year of the plant's life, 40% in the subsequent year and 20% in the following year. In conjunction with PP&L's most recent base rate case at Docket No. R-00943271, PP&L submitted a study that estimated the Company's decommissioning costs for its wholly-owned fossil plants. See PP&L's response to the Commission's filing guideline at Appendix A, Section L, Item 2 for the decommissioning study completed for fossil plants. Decommissioning estimates for Keystone and Conemaugh are based on a 1996 study conducted by an independent consultant and well provided by the plant operator.

Taxes Other Than Income

I calculated the annual expense for taxes other than income. Taxes other than income applicable to fossil plant generation include an allocated portion of the Company's expense for Pennsylvania capital stock tax and Pennsylvania public utility realty tax. I escalated these taxes at a rate of 2.5% for the remaining lives of the fossil generation plants.

Contracts with NUGs

Q. Please describe the stranded cost NUG calculation.

A. I calculated stranded costs associated with NUG contracts by comparing the difference between the contract cost of output purchased from NUGs, beginning January 1, 1999 through the end of the contract terms, to the market value of that output. I adjusted this difference for the PUC jurisdictional portion and discounted the difference to determine the present value at January 1, 1999. In addition, I included the present value of payments occurring after December 31, 1998 for buyout costs associated with two NUG contracts discussed below. A summary of NUG costs is provided at Tab E of Exhibit JRS 1.

Purchases

I calculated the amount the Company will have to pay to each NUG, in most cases, by multiplying the estimated output purchases from the NUG by the contract price. Annual output purchased from each NUG is estimated to equal the average annual generation during the three years 1994-1996 and is assumed to continue at this level until the contract ends.

This approach, however, was not applicable to three NUG contracts. First, for one NUG which recently became dispatchable in lieu of being a must-run unit for generation scheduling purposes, I directly included the projected amount of payments to that NUG. Second, for a NUG that is forecasted to come on-line January 1, 1998, I used an 80% capacity factor to estimate annual output purchases, based on information the NUG provided to the FERC. Third, I used the 1996 capacity factor to estimate annual output purchased for a NUG that only reached its "normal" operating capacity in 1996.

Market value of output purchased from NUGs

The market value of the purchased output was calculated by multiplying the output purchased by the projected market clearing price of generation (MCPG), supplied by Dr. Jones. For all NUGs, except the one that is dispatchable, the MCPG is the weighted average market price that applies to base-load units. For the dispatchable NUG, the market price used is the peak MCPG, because the output of this NUG is dispatched only during times of peak system demand

Buyout costs

As part of the Company's efforts to mitigate stranded costs, PP&L has entered into agreements to buy out contracts with two NUGs. One buyout has been approved by the Commission, and another buyout is still pending Commission approval. The payments to be made after December 31, 1998 to buy out these two contracts are included in the calculation of the Company's stranded costs.

Regulatory Assets

Q. Please describe the calculation of stranded costs relative to regulatory assets.

A. Regulatory assets are costs, incurred by entities subject to cost-based rate regulation, the recognition of which as an expense of which is deferred to the time that Commission-approved rates authorizing the recovery of the cost are recovered from customers. Entities that are not subject to cost-based regulation recognize such costs as an expense when incurred.

The Company's calculation of stranded costs related to regulatory assets is the present value at January 1, 1999 of the PUC jurisdictional portion of net regulatory assets that are generation-related and are comprised of:

- Unrecovered energy costs
- Post-retirement benefits other than pensions
- Deferred Susquehanna operating and carrying costs
- Utility plant carrying charges on common facilities after in-service date
- Retired miners' health care costs
- DOE assessment
- Deferred Susquehanna refueling costs
- Voluntary early retirement plan
- Employee transition costs

- Rate case expenses
- Taxes recoverable
- Investment tax credits (regulatory liability)

A summary of the Company's regulatory assets and their amortizations is provided in Tab F of Exhibit JRS 1.

Unrecovered Energy Costs

On January 1, 1997, PP&L's energy costs, which were being recovered through the ECR, were rolled into base rates, and the ECR became inactive. As of that date, PP&L had uncollected energy costs of $17.2 million associated with the ECR. The Commission issued a tentative order at Docket Nos. P-00961131 and R-00963842 allowing PP&L to defer as a regulatory asset its uncollected energy costs as of December 31, 1996, as well as future amounts that represent the difference between the amount of energy costs rolled into base rates and PP&L's estimated on-going energy costs. PP&L booked as a regulatory asset $16.9 million of the 1996 undercollection in December 1996 and the remaining $0.3 million in January 1997. Average on-going energy costs for 1997 and 1998 are estimated to exceed the amount rolled into base rates by $31.5 million per year for PUC jurisdictional customers.

I included in the calculation of stranded costs the $17.2 million of actual uncollected energy costs as of December 31, 1996 and $31.5 million of estimated unrecovered on-going energy costs for the years 1997 and 1998.

Post-retirement Benefits Other Than Pensions

The Commission, in its Final Order at Docket No. R-00943271, permitted recovery of the PUC jurisdictional amount of retiree health care costs resulting from the adoption of Statement of Financial Accounting Standard No. 106 (SFAS 106), "Employers' Accounting for Post-retirement Benefits Other Than Pensions." In addition, the PUC permitted PP&L to recover, over a period of about 17 years, the amount of SFAS 106 costs that would have been deferred from January 1, 1993 through September 30, 1995.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of the generation-related amount of these costs.

Deferred Susquehanna Operating and Carrying Costs

The PUC, in its Final Order at Docket No. R-00943271, permitted recovery over 10 years of certain deferred operating and capital costs, net of energy savings, incurred from the time Susquehanna Unit 2 was placed in commercial operation until the effective date of base rate recognition for that Unit.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of these costs.

Utility Plant Carrying Charges on Common Facilities After In-Service Date

PP&L has certain facilities that serve dual-unit power plants and are generally referred to as common facilities. Although these facilities generally are placed in service with the first unit, Pennsylvania ratemaking traditionally has allowed only one-half of common facilities to be included in rate base when the first unit is placed in service. Consequently, one-half of common facilities remains in construction work in progress after the first unit at the plant is placed into service and continues to accumulate carrying charges until the final unit is placed in service. The regulatory asset represents carrying charges on common facilities that were not included in rates when Susquehanna Unit 1 and Martins Creek Unit 3 were placed in commercial operation. These charges were reclassified in 1987 from electric utility plant in service to a deferred debit in accordance with a FERC order. Such charges are being amortized over the remaining depreciable life of the related property and are included in PUC jurisdictional electric service rates.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of these costs.

Retired Miners' Health Care Costs

The Energy Policy Act of 1992 imposed a liability on PP&L for the health care of retired coal miners. The Commission allowed recovery of the PUC jurisdictional portion of these costs through the ECR over a 10-year period beginning on

April 1, 1994. In January 1997, the portion of the liability that was recorded on a subsidiary's books was transferred to PP&L's books to maximize tax benefits, and PP&L reduced the regulatory asset by the additional tax benefits of $1.56 million.

Because the calculations for the health care benefits already are stated on a present value basis and apply only to PUC jurisdictional customers, I included in the calculation of stranded costs the recorded value of the regulatory asset at January 1, 1999

DOE Assessment

The Energy Policy Act of 1992 provides for an assessment, over a 15-year period, on utilities with nuclear power operations, including PP&L, to provide funds for the decontamination and decommissioning of the Department of Energy's ("DOE") uranium enrichment facilities. The Energy Act states that the assessment shall be deemed a necessary and reasonable current cost of fuel and shall be fully recoverable in rates in all jurisdictions in the same manner as other fuel costs.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of this assessment.

Deferred Susquehanna Refueling Costs

This regulatory asset represents incremental maintenance costs incurred during refueling and inspection outages which are deferred and subsequently amortized from the end of the outage until the next scheduled refueling and inspection outage is completed.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of these costs.

Voluntary Early Retirement Plan

The Commission, in its Final Order at Docket No. R-00943271, permitted the Company to recover over five years the PUC jurisdictional cost of the 1994 Voluntary Early Retirement Program.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the PUC jurisdictional portion of the generation-related portion of these costs.

Employee Transition Costs

I estimated additional severance and incremental pension costs expected to be incurred between 1997-2001 as a result of the Company's projected decline in the number of employees due to its efforts to prepare for a competitive market. PP&L's Human Resources and Development Department provided the per-employee estimate for these transition costs. I calculated a 5-year amortization period for these costs incurred in each of those years. I included in stranded costs the present value of the PUC jurisdictional portion of the generation-related portion of these costs.

Rate Case Expenses

The Commission, in its Final Order at Docket No. R-00943271, permitted the Company recovery, over four years, of expenses incurred in connection with that rate case.

I calculated the annual recovery that would occur through existing rates and included in the stranded cost calculation the present value of the generation-related portion of the costs.

Taxes Recoverable

Taxes recoverable represent tax liabilities that (1) emanate from past regulated operations which have not been funded by ratepayers and (2) the Company is obligated to pay to taxing authorities in the future. Taxes recoverable arise from differences between book and tax depreciation and from differences in how the cost of property is calculated for book and tax purposes.

The Internal Revenue Code permits taxpayers to depreciate the cost of plant and equipment over periods that generally are shorter than the property's useful life, as determined under generally accepted accounting principles. Rates are set using the longer GAAP lives. Accordingly, in the initial years of the property's life, the cost of the property is depreciated faster for tax purposes than for regulatory purposes. This higher level of tax depreciation results in tax benefits greater than the level associated with the book depreciation used for ratemaking purposes. Conversely, depreciation of the same property in the later years of its life is lower for tax purposes than for regulatory purposes. Because the Company made the bulk of its capital improvements a number of years ago, book and regulatory depreciation currently exceeds tax depreciation for many of the Company's assets.

In Pennsylvania, utility rates traditionally have been set based on the doctrine of "actual taxes paid," except where Federal law requires normalization. Consequently, the tax benefits produced by the difference between book and tax depreciation are used to reduce customers' rates below the levels that otherwise would apply in the absence of such tax benefits.

A second difference between book and tax cost arises from the accounting for financing costs. Cost for book and regulatory purposes includes the cost of debt and equity issued to finance construction. Until the early 1980's, the tax cost excluded this cost of money. In 1982 and 1986, Congress changed the tax rules to require that interest costs be capitalized.

Pursuant to its adoption of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS 109), PP&L calculated the amount of taxes recoverable, as follows: In determining the amount of deferred taxes required under the standard, PP&L calculated the total amount of taxes that would have been recorded on the Company's books, if the Company had fully normalized income taxes to reflect the book/tax timing differences discussed above. The total amount of deferred taxes that would have been recorded if PP&L had recognized these differences was compared to the amount of deferred income taxes already recorded on the Company's balance sheet. The net difference, or the amount of unrecorded deferred taxes, was then "grossed up" to produce the appropriate revenue requirements level. The sum of the unrecorded deferred tax amount and applicable revenue requirements "gross up" component represents the SFAS 109 taxes recoverable amount which is recorded currently on the Company's balance sheet and would be recoverable through future rates under traditional regulation.

I calculated the annual amortization amount of generation-related taxes recoverable applicable to PUC jurisdictional customers beginning January 1, 1999 that would apply under traditional regulation and included in the stranded cost calculation the present value of that annual amortization.

Investment Tax Credits (Regulatory Liability)

When Federal tax law allowed the Company to take advantage of investment tax credits, the Company deferred immediate recognition of these credits as income by recording a liability for accumulated deferred investment tax credits. The amortization of accumulated investment tax credits, including the associated income tax effect, reduces the cost-of-service over the lives of the assets that generated the investment tax credits, and accordingly, customer rates. In connection with the adoption of SFAS 109, the Company recorded a deferred tax asset for the associated income tax effect of accumulated deferred investment tax credits and a regulatory liability to recognize the ratemaking treatment of the tax effect.

I calculated the annual amortization of the generation-related portion of the regulatory liability applicable to PUC jurisdictional customers beginning January 1, 1999 that would apply under traditional regulation and reduced the stranded cost calculation by the present value of the annual amortization.

Market revenues

Q. Please explain the calculation of future revenue recovery in a competitive market.

A. In a competitive market, the sales price of a product or service is set by market forces, not by cost-of-service rate regulation. Thus, future revenues will depend upon the market price of electricity. To determine revenues in this context, one must project the market price of electricity and then determine the market revenue expected from each of the Company's generating plants. These projections and calculations are discussed more fully in the testimony of Dr. Scott T. Jones. A summary of the market prices used in PP&L's stranded cost calculation is provided in Tab J of Exhibit JRS 1.

Q. Please explain how you utilized these market price and market revenue inputs in your analysis.

A. For the nuclear generating plant and for each fossil generating plant, I used the revenue projections applicable to each plant for each year from January 1, 1999 to the end of that plant's life

For each NUG contract, I applied the market price of electricity to the projected output purchases for each year beginning January 1, 1999 to the end of the contract term.

Calculation of stranded costs

Q. Please explain how these two revenue streams were compared and discounted.

A. For the nuclear plant and for each fossil generating plant, I calculated the difference between its projected market revenue and its projected revenue requirement for each year from January 1, 1999 to the end of its useful life.

For each year from January 1, 1999 to the end of the contract term, I calculated, for each NUG, the difference between (1) the projected market value of the output purchased and (2) the cost of that output under existing contract rates or the buyout payments projected to occur after 1998.

I then discounted each generating plant's and each NUG's stream of differences between market revenues and revenue requirements using a discount rate of 7.92%.

For regulatory assets, I calculated the annual PUC jurisdictional amount of the amortization of generation-related regulatory assets. Because market revenues are not associated with regulatory assets, I discounted that stream of amortizations to January 1, 1999 at a 7.92% discount rate.

Q. How is the discount rate derived?

A. The discount rate of 7.92% used in the calculations is the Company's weighted after-tax cost of capital as of December 31, 1996. Details are provided in Tab A of Exhibit JRS 1.

Q. Have you reflected mitigation efforts in your analysis?

A. Mitigation measures are specifically discussed in Mr. Hill's testimony. For purposes of my testimony, there are two categories of mitigation, past and future. Past mitigation efforts are reflected in PP&L's current rates which are below the Pennsylvania average and very near the national average. Without this mitigation, PP&L's rates would be much higher today and so would its stranded costs. Future mitigation relates to PP&L's plans that have not yet been implemented. If these efforts are successful, they will reduce the Company's stranded costs. Even though there is no assurance that this future mitigation will occur, PP&L has elected to deduct these projected mitigation efforts from its stranded cost claim.

Q. What is the impact of future mitigation efforts on the Company's stranded costs?

A. The Company's stranded costs would be more than 20% higher without future mitigation efforts. This difference of over $1 billion is comprised of:

- $649 million reduction in nuclear generating plant costs
- $258 million reduction in fossil generating plant costs
- $100 million for NUG buy-outs

Q. What are the Company's total stranded costs net of future mitigation efforts?

A. The Company's stranded costs, net of future mitigation efforts, total $4,611 million and are comprised of:

$2,852 million for nuclear generating plant costs

$718 million for fossil generating plant costs

$657 million for NUGs

$384 million for regulatory assets

Exhibit JRS 1 provides the details of the Company's stranded costs after mitigation.

Q. Does this conclude your testimony?

A. Yes, it does.