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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY AND EXHIBITS OF

PETER F. CHAMBERLAIN

ON BEHALF OF BOC GASES

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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DOCKET NO. R-00943271

DIRECT TESTIMONY AND EXHIBITS OF

PETER F. CHAMBERLAIN

ON BEHALF OF BOC GASES

Q. **What is your name and title?**

A. My name is Peter F. Chamberlain. I am Manager, Utilities and Regulatory Affairs for BOC Gases. My educational background and employment history is set forth in Appendix A.

Q. **Who is BOC Gases?**

A. BOC Gases is the second largest industrial gases supplier in the world. We manufacture and market nitrogen, oxygen and argon at atmospheric plants. We purify, liquefy, and distribute CO_2 at other facilities as well as helium and hydrogen.

Q. **Is BOC served by PP&L?**

A. Yes. Our Bethlehem, Pennsylvania, facility takes electric service from PP&L.

Q. Please describe your Bethlehem facility.

A. Certainly. Our Bethlehem facility was constructed in 1968, primarily to provide oxygen to the Bethlehem Steel mill. It consists of two air separation units (ASUs) with a capacity of producing 550-600 tons of gaseous oxygen per day and two liquefiers with a combined capacity of liquefying over 900 tons of oxygen and/or nitrogen.

Q. Could you please describe your operation in Bethlehem.

A. BOC produces oxygen, nitrogen and crude argon cryogenically at Bethlehem. By that I mean, we use cooling processes to produce these valuable industrial gases.

The process is fairly straightforward. We take air and liquefy it by cooling it down to below -300°F. This "liquid air" is then sent to a distillation column where air's major components (oxygen, nitrogen and argon) are separated through evaporation in the column. Gaseous oxygen is piped directly to Bethlehem Steel. The remaining oxygen and nitrogen is then liquefied for sale to hospitals, electronic companies, and other companies for industrial purposes.

Q. How do you use electricity?

A. In order to cool air down to -300°F, a large compressor liquefies the air using the same basic theory used in one's refrigerator. Compressors are driven by large electric motors. Similarly, each of air's major components (eg. oxygen and nitrogen) are liquefied for truck shipment. This is accomplished by another compressor which is driven by a large electric motor. These motors account for over 90% of the electric usage on an annual basis.

Q. **Why do electric costs represent such a large portion of BOC's costs?**

A. Our raw material - air - is free. Therefore, our production costs are basically for electricity, salaries and supplies. Other industries, like the paper industry for example, have labor costs, pulpwood costs, chemical costs and energy costs. While electricity costs in the paper industry are probably less than 5% of total production costs, electricity costs for BOC at Bethlehem exceed 70% of total production costs.

Q. **Is there any other industry whose electricity costs represent such a large portion of its costs?**

A. No. Even for industries that use electrolysis, such as the chlor-alkali industry, electricity costs represent 30% to 40% by our estimates.

Q. Can you tell us more about BOC's Bethlehem's operation?

A. Certainly. We currently employ 19 full-time employees. Annual salaries and benefits for 1994 totaled over $1,000,000. BOC Gases paid $60,000 in state income taxes, and $115,000 in state real estate taxes. In addition, BOC paid $48,000 in sales tax, $33,000 in city payroll taxes, $360,000 in state payroll taxes and $185,000 in unemployment taxes. These taxes total approximately $813,000 per year.

Q. What other value do you provide to the community?

A. BOC purchases over $900,000 worth of goods and services throughout the Commonwealth.

Q. Is BOC Gases an interruptible customer of PP&L?

A. Yes, BOC Gases is one of the original PP&L interruptible customers. We have been on PP&L's Rate LP-5 - Optional Interruptible Power since it was first introduced in August of 1992. Prior to that, BOC purchased service from PP&L pursuant to the Interruptible Service by Agreement tariff, and, before that, Rate Schedule IS-2.

Q. What percentage of the plant's variable production costs does electricity represent at your Bethlehem facility?

A. Approximately 91% in fiscal year 1994. Since our raw material is air, virtually all of our direct production costs are electricity. As a percentage of total production costs, (including depreciation), electric costs represent 71%.

Q. Have you estimated the impact of PP&L's proposed filing on your electric costs?

A. Yes, we have. If PP&L's proposed rates were put into effect, BOC's costs would rise approximately 24.4%, or over $1,500,000 annually, based on 1994 usage and load profile.

Q. What is the future of the Bethlehem plant?

A. As I mentioned earlier, we provide approximately 400 tons per day of oxygen to Bethlehem Steel. As many are aware, the steel mill is shutting down a major portion of the mill's operation and will cease taking oxygen from BOC in late 1995.

Q. What impact will that have on BOC?

A. The impact will be severe. First, our facility was designed and built primarily to serve Bethlehem Steel, providing gaseous oxygen. As a result, our air separation units (ASUs) were sized to serve the mill's load plus that gas which is liquefied to serve our merchant and wholesale market.

Q. What are the practical consequences to the operation of your facility when Bethlehem Steel ceases operation?

A. The result will be a significant mismatch between our ability to produce gaseous oxygen and nitrogen and our ability to liquefy these products. We will be forced to "vent" gaseous nitrogen and oxygen back into the atmosphere and liquefy what product we need to serve our liquid market.

Q. Why don't you reduce the output of the ASU to match your liquid requirements?

A. ASU's have only a limited ability to be "turned down" -- that is to say, reduce output. Below 70 to 75% of rated capacity, our Bethlehem ASU's become very inefficient and can lose purity in the distillation column. Even for operations above 70%, efficiencies drop as you reduce output from 100%.

Q. Does your Bethlehem facility compete for sales of liquid oxygen and nitrogen?

A. Yes, BOC competes with Air Products in Lancaster, PA, Praxair in Hatfield, PA, Liquid Carbonic in Stockertown, PA (all served by PP&L), Liquid Air in Coatesville, PA (served by PECO Energy Company), and MG Industries in Reading, PA (served by Met-Ed).

Q. **Does the Bethlehem facility compete with any other plants?**

A. Yes. We have liquid capacity in Claymont, Delaware, Arroyo, West Virginia, and Selkirk, New York. Moreover, because our plants form a supply network reaching from Kittery, Maine, to Joliet, Illinois, and south, a reduction in output from one facility can be made up from one as far away from Bethlehem as Maine or Illinois.

Q. **Does BOC have excess capacity in its east coast network?**

A. Yes, although the level of excess varies with season and market conditions.

Q. **In today's market for liquid oxygen and nitrogen, could the liquid nitrogen/oxygen (LOX/LIN) output from the Bethlehem plant be made up from other BOC sources?**

A. Yes. The current LOX/LIN loading at Bethlehem could be made up from other plants in our system, thereby eliminating the need for liquid product off of our Bethlehem plant. Under this scenario, the need for continued operation at Bethlehem would be seriously questioned.

Q. How do electric rates at these other locations compare with PP&L's proposed rates?

A. Very favorably. For competitive reasons, I will not cite specific rates. However, PP&L's proposed rate for interruptible power exceeds all but one rate at another location and that rate is for firm service.

Q. How do efficiencies at these other locations compare to the Bethlehem facility?

A. Even with the steel mill taking oxygen, our Bethlehem plant is the most inefficient plant among those with capacity to replace LOX/LIN being produced at Bethlehem. As I discussed earlier, the efficiency will decline substantially when the steel mill ceases taking gaseous oxygen from our facility.

Q. What were the future plans for the Bethlehem facility prior to the filing of this rate case?

A. The future was very much in doubt. Several factors were being considered and weighed including the value of keeping Bethlehem open to "back-up" certain facilities, the value of Bethlehem as a "swing" plant -- that is operated when product was tight in the region, and the relative delivered cost of product from Bethlehem compared to other BOC plant locations or through competitor purchases.

Q. What is the effect on future plans for Bethlehem if PP&L receives approval of its rate proposals?

A. Bethlehem will go from being a very marginal plant to a very uneconomic plant. We will not operate a facility at a loss unless meeting existing customer product requirements demand that we do so. We certainly would take on no new customers if the incremental costs of production are greater than the price we receive for the product, on a delivered basis.

Q. If PP&L received <u>no</u> overall increase but received approval of its rate design changes to LP-5 interruptible customers, what would be the effect on BOC's electric rates?

A. PP&L responded to an on-the-record data request made on March 29, 1995 and indicated that if no increase in revenue requirement is granted by the Commission, Rate Schedule LP-5 interruptible customers would still receive a <u>22.46%</u> increase if the rate design modification as proposed by PP&L for LP-5 interruptible customers is approved. (<u>See</u> DR-PPLICA-5 attached as Ex. PFC-1).

Q. Has BOC ever experienced an increase in rates of 22.46% in one rate case when a utility's overall revenue requirement is not increased by the Commission?

A. No. I joined BOC Gases (then Airco Industrial Gases) in

1989. I am aware of no increases anywhere at any of the over 40 locations we operate across the country, where we have experienced a 22.46% increase in one rate case, let alone PP&L's <u>proposed</u> 27% increase to interruptible customers. BOC did not even experience increases of this magnitude when its serving utilities were adding significant rate base additions. Here, BOC is exposed to a potential 22.46% rate increase even if the Commission holds PP&L's current revenue requirement constant.

Q. **What are you asking this Commission to do?**

A. BOC respectfully requests that this Commission review the extensive analysis and testimony that our expert consultants have prepared and adopt their recommendations. The chilling effect on job creation of such draconian and, we believe, warranted modifications to rates cannot be overstated. In particular, the Commission must be sure to prevent a rate design change to Rate Schedule LP-5 - Optional Interruptible Power which produces a 22.46% rate increase for those customers even if PP&L's total revenue requirement requested increase is reduced to zero.

Q. **Does this complete your testimony?**

A. Yes, it does.

BIOGRAPHY OF PETER F. CHAMBERLAIN

Mr. Chamberlain is Manager, Utilities and Regulatory Affairs for BOC Gases, a division of the BOC Group Ltd., its British Parents. Mr. Chamberlain is responsible for electric contract negotiations, regulatory activities, and lobbying activities.

Mr. Chamberlain has testified before state and federal regulatory agencies and before the United States Congress on energy matters.

Mr. Chamberlain received his Bachelors degree in Electrical Engineering from Clarkson University in 1973 and his MBA from the Wharton School of the University of Pennsylvania in 1979.

Mr. Chamberlain works out of BOC's Murray Hill, NJ, headquarters for the Americas.

Prior to joining BOC Gases, Mr. Chamberlain was employed for ten years by Westvaco Corporation, a large forest products and chemical company. He served as Westvaco's corporate energy manager, responsible for energy purchases of electricity and natural gas.

APPENDIX A

O. G. Kasper

Pennsylvania Power & Light Company
Response to Data Request of
PP&L Industrial Consumers Alliance
March 29, 1995 Hearing (Tr. 806-807)
Docket No. R-00943271

Q.DR-PPLICA-5. Please quantify what the average percentage increase would be for Class LP-5I customers assuming PP&L's rate structure proposals are approved but no rate increase is granted.

A.DR-PPLICA-5. If no increase is granted, but the proposed structure of Rate Schedule LP-5(I) remains as filed, Rate Schedule LP-5(I) customers would receive an overall increase of 22.46%. Because the resulting hypothetical design does not involve any roll-in, current adjustments are applied to present and proposed base rates. EDI credits apply to the proposed rate only.

The above hypothetical rate design was developed only for the purpose of responding to this data request. PP&L does not represent that this design will be retained if the Commission grants other than the proposed rate increase.

EXHIBIT PFC-1

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

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DIRECT TESTIMONY OF

PAUL R. WILLIAMS

ON BEHALF OF AIR PRODUCTS AND CHEMICALS, INC.

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

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APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF PAUL R. WILLIAMS

ON BEHALF OF AIR PRODUCTS AND CHEMICALS, INC.

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

A. My name is Paul R. Williams. I am an energy analyst for Air Products and Chemicals, Inc. (Air Products), at its headquarters located at 7201 Hamilton Boulevard, Allentown, Pennsylvania 18195.

Q. Briefly describe your educational and professional background.

A. I studied Electrical Engineering at Drexel University in Philadelphia, where my concentration was Power Systems, and I graduated with a Bachelor of Science in Electrical Engineering degree in 1988. I also studied Engineering Management at Drexel University, where my concentration was Utility Management, and I received a Masters of Science in Engineering Management degree in 1991.

I began my professional career with Philadelphia Electric Company (PECO) in 1988. While at PECO I performed various functions in their Rates Department, including rate design, cost of service and revenue requirements analysis. I prepared testimony, exhibits and various filings for Pennsylvania, Maryland and FERC jurisdictions. In 1994 I joined Air Products, where I am responsible for the electricity supply arrangements for existing and proposed plant sites in a number of states. My specific duties include the negotiation of power contracts, rate case interventions, and power cost forecasting in Pennsylvania.

Q. **How many Air Products facilities are located on the Pennsylvania Power & Light (PP&L) system and how many people do they employ?**

A. Air Products has five major facilities located on the PP&L system. They are our Lancaster air separation facility, our International Headquarters in Trexlertown, our Hometown manufacturing facility, our Wilkes-Barre manufacturing facility, and our Gardner Cryogenics plant in Bethlehem. In addition to these facilities, Air Products has numerous smaller commercial facilities located throughout the PP&L service territory. Air Products employs in excess of 4,900 people at facilities located within PP&L's service territory.

Q. What contributions does Air Products make to the PP&L service territory?

A. As previously stated, Air Products employs in excess of 4,900 individuals at facilities located throughout the PP&L service territory. Annual payroll to Air Products' employees in the PP&L service territory is approximately $350 million. State and local income taxes on these wages produce in excess of $10 million for state and local governments. Although it is impossible to accurately measure the total contributions through federal, state and local income taxes, state sales and use taxes, and real estate taxes paid by our employees, it is not unreasonable to estimate that the total would exceed $100 million per year paid to local, state and federal governments.

In addition to employee costs, Air Products spends approximately $40 million on goods and services from the communities within the PP&L service territory each year, pays $1.4 million in property taxes, and in excess of $15 million in state unemployment, federal and state corporate net income, and federal social security taxes.

Q. **What type of products are produced by Air Products in the PP&L service territory?**

A. Approximately 75% of the energy consumed by Air Products on the PP&L system is used to produce liquid nitrogen, liquid oxygen, crude argon and various specialty gases. Air Products currently purchases that energy from PP&L on Rate Schedule LP-5 - Optional Interruptible Power. The remaining 25% is consumed at commercial facilities, in research and development and the manufacture of specialty equipment. The industrial gases produced by Air Products are used by some of the regions largest employers in the hospital/medical, metals, fertilizer, food processing, electrical/electronics, and pharmaceutical industries.

Q. **Why is the cost of electricity so important to Air Products?**

A. The air separation process involves the compression and refrigeration of atmospheric gases, allowed by expansion of the gas within distillation columns to separate the elements of atmospheric gas based on the differences in boiling/

condensing temperatures of the different components: nitrogen and oxygen primarily. The air separation process is electricity intensive. In essence, electricity is the basic raw material in the production process and accounts for 60 to 70 percent of the cost of production at an air separation facility. At this time Air Products purchases in excess of 240 million kilowatt-hours annually from PP&L at a cost of more than $10 million.

Q. **What would be the impact of the PP&L proposed base rate increase on Air Products industrial gas production facilities?**

A. Air Products production facilities on the PP&L system compete against other industrial gas producing facilities located in other parts of Pennsylvania, Delaware, Maryland, New York, North Carolina, Ohio, and West Virginia. Many of these competing facilities already pay significantly less for electricity than Air Products' facilities located on the PP&L system. The total impact on Air Products of PP&L's proposed new rates would be an electricity cost increase in excess of $2.2 million per year.

The magnitude of the cost increase that Air Products would experience as a result of the PP&L rate proposal is unreasonable. At Air Products' industrial gas production facilities the electricity cost increase would approach 28%. An instantaneous 28% cost increase in our largest production cost component has a significant harmful effect on the ability of Air Products' Lancaster facility to compete against other industrial gas producing facilities. This is particularly offensive when compared to the recent rate reductions that PP&L has given to municipal wholesale customers. In fact, after the final rate reduction becomes effective for PP&L's wholesale customers on January 1, 1996, PP&L's current proposal would force Air Products to pay in excess of 20% more for interruptible power than a firm wholesale customer pays when served at the same voltage levels. Over the long run, the PP&L proposal can only lead to decreased investment and employment within the PP&L service territory.

Q. **What do you want the Commission to do in this case?**

A. I recommend that the Commission adopt the proposals made by PPLICA's expert witnesses on revenue requirement, rate design, and cost of service.

Q. Does this complete your testimony at this time?

A. Yes it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF

JAMES S. SCHNEIDER

ON BEHALF OF R. R. DONNELLEY & SONS, INC.

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF JAMES S. SCHNEIDER

ON BEHALF OF R. R. DONNELLEY & SONS, INC.

Q. Please state your name and business address.

A. My name is James S. Schneider and my business address is R. R. Donnelley & Sons, Inc., 216 Greenfield Road, Lancaster, PA 17601-5885.

Q. What is your position with R. R. Donnelley & Sons, Inc.?

A. I am the Senior Electrical Engineer with responsibility for Energy Affairs at Donnelley's Lancaster area facilities. Attached as Appendix A is a description of my educational background and employment history.

Q. Can you describe for the Commission the type of business in which R. R. Donnelley & Sons, Inc. is involved?

A. Donnelley is a leader in the printing and related technologies industries and has more than 200 manufacturing and non-manufacturing facilities worldwide. 1994 gross sales for the company exceeded $4.8 billion and our employment levels exceeded 39,000 worldwide.

Q. What facilities does Donnelley have in PP&L's service territory?

A. Donnelley has four major printing facilities in Pennsylvania, all located in PP&L's service territory:

R.R. Donnelley & Sons, Inc.
Lancaster East Facility
216 Greenfield Road
Lancaster, PA 17601

R. R. Donnelley & Sons, Inc.
Lancaster West Facility
1375 Harrisburg Pike
Lancaster, PA 17601

R. R. Donnelley & Sons, Inc.
Steelway Facility
391 Steelway
Lancaster, PA 17601

Haddon Craftsmen, Inc.
Division of R. R. Donnelley & Sons, Inc.
Wyoming Avenue & Ash Street
Scranton, PA 18509

At these facilities, Donnelley employs over 2,800 people.

Q. How does Donnelley utilize the electricity it purchases from PP&L?

A. While electricity is one of a number of manufacturing costs associated with the printing industry, it is used in nearly every facet of the manufacturing process from prepress through printing to binding and shipping. Our principal use of electricity is to operate the printing presses which transport paper through the printing units, thus allowing ink to be applied to the paper in the printing process. The price of electricity is extremely important to Donnelley because the printing industry is highly competitive and Donnelley is continuing to search for ways to become the lowest cost supplier.

Q. Does Donnelley make significant contributions to the local and state economy?

A. Yes. During 1994, Donnelley invested more than $49 million at its facilities in Pennsylvania and anticipates an additional expenditure of $49 million in 1995. Among these investments were a recently completed $30 million investment at our Lancaster-based West Facility which added approximately 100 new employees. We recently began a $70 million investment at our Lancaster-based East Facility which we believe will add an additional 100 employees to the local economy.

In order to convey the magnitude of Donnelley's operations in Pennsylvania to the Commission, I would like to note that Donnelley purchased more than $121 million of services from the U.S. Postal Service in the Lancaster area alone. During 1994, Donnelley also purchased approximately $1.85 million of services from trucking firms located within the south-central Pennsylvania region. We estimate that in a typical year, Donnelley purchases more than $3 million of materials and labor within the Commonwealth of Pennsylvania in 1994.

With our employment level in excess of 2,800, our employees contributed in excess of $3.4 million in state and local taxes and Donnelley alone paid more than $2.2 million in taxes to the Commonwealth of Pennsylvania in 1994.

Q. **Pursuant to what rate schedules does Donnelley purchase electricity from PP&L?**

A. The majority of Donnelley's consumption is purchased pursuant to Rate Schedule LP-5 on both a firm and an Optional Interruptible Power basis. Annual consumption is approximately 110 million kWh at an average cost of 4.49¢ per kWh.

Q. **What is the impact of PP&L's proposed rate increase on Donnelley?**

A. If PP&L receives the increase requested as well as the modifications to the LP-5 interruptible rate design, the increase to Donnelley will be in excess of $1 million per year in Pennsylvania. Such an increase would change the average cost per kWh of electricity mentioned previously of 4.49¢ per kWh to 5.41¢ per kWh. This would represent an increase in excess of 21% to the average cost of electricity purchased by Donnelley from PP&L.

Q. **How do Donnelley's current average cost per kWh of 4.49¢ per kWh and the PP&L proposed average cost per kWh of 5.41¢ per kWh compare to the electricity prices of Donnelley's other divisions which produce similar products to those at Donnelley's Lancaster facilities?**

A. Not very well. Listed below are six facilities within Donnelley all of which compete directly with Donnelley's Lancaster facility and which have average costs per kWh well below Donnelley's present and proposed average cost per kWh in PP&L's service territory:

Des Moines, Iowa: 3.76¢/kWh
Danville, Kentucky: 3.22¢/kWh
Glasgow, Kentucky: 3.94¢/kWh
Daytona, Florida: 3.94¢/kWh
Mattoon, Illinois: 4.43¢/kWh
Willard, Ohio: 4.0¢/kWh.

If PP&L's proposal is accepted by the Commission, our Lancaster facilities would also be paying an average cost per kWh in excess of our Dwight, Illinois facility which currently has a 4.7¢ per kWh average cost of electricity. Thus, if PP&L is "successful" in this proceeding, the only two remaining Donnelley facilities which would have an electricity cost in excess of PP&L's would be our Old Saybrook, Connecticut, facility with an average cost of 5.62¢ per kWh and our Los Angeles, California, facility with an average cost of 8.61¢ per kWh. However, due to the geographical distance between Lancaster, Pennsylvania, and Los Angeles, California, our Lancaster plant does not compete directly with the Los Angeles facility.

Q. What can this Commission do to lessen the impact of PP&L's proposal on Donnelley in this proceeding?

A. The adverse impact on Donnelley is caused not only by PP&L's proposed base rate increase but also by PP&L's proposed revision to the rate design for the LP-5 - Optional Interruptible Power service. Donnelley urges the Commission to accept the recommendation of the PP&L Industrial Customer Alliance expert witnesses with respect to both the final increase to which PP&L may be entitled and with respect to the appropriate rate design for the LP-5 - Optional Interruptible Power group of customers.

Q. Does that complete your testimony at this time?

A. Yes and thank you.

JAMES E. SCHNEIDER

Bachelor of Science in Electrical Engineering (Power) from Clarkson University, Potsdam, New York.

Completion of course work for Master of Business Administration at Penn State University (Harrisburg).

1978-1980 - Employed by New York State Electric & Gas Corporation in their Corporate Market Service Department.

1981-Present - Employed by R. R. Donnelley, Inc. in Lancaster, Pennsylvania, in various roles with increasing responsibility within engineering, project design and installation, project and contractor management, and energy affairs.

APPENDIX A

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF

DON A. HORNUNG

ON BEHALF OF HERSHEY FOODS CORPORATION, INC.

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF DON A. HORNUNG

ON BEHALF OF HERSHEY FOODS CORPORATION, INC.

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

A. My name is Don A. Hornung. I am an energy manager for Hershey Foods Corporation, Inc. ("HFC"), at 19 East Chocolate Avenue, Hershey, Pennsylvania 17033.

Q. Briefly describe your educational and professional background?

A. I was awarded a Bachelor of Arts Degree in Biological Sciences in 1972 from Mansfield State College. From 1973 until 1990, I held various specialist and managerial positions within HFC's environmental departments. In 1990, I began a development assignment to improve HFC's competitive position as it relates to energy and to identify any synergies from the melding of energy and environmental issues.

I and my staff currently support HFC's twenty-seven (27) North American (Canada, United States, Mexico) facilities on energy-related matters. This responsibility includes natural gas purchasing and transportation, alternate fuels, electric power purchases, evaluating electric power alternatives, review of energy-related capital project proposals, and represent HFC's business interests on energy matters at the state and federal level.

Q. **On whose behalf are you appearing in this proceeding?**

A. I am appearing on behalf of my employer, Hershey Foods Corporation, Inc. ("HFC"), which is participating in this proceeding as a member of the PP&L Industrial Customer Alliance ("PPLICA").

Q. **How many HFC facilities are located on the Pennsylvania Power & Light ("PP&L") system and how many people do you employ?**

A. HFC currently has fifteen (15) major facilities in PP&L's service territory. The total employment at these locations is approximately 7,300. These employees represent approximately 60% of HFC's North American work force.

Q. Has HFC's level of commitment, in the PP&L service territory, increased since PP&L's last base rate case?

A. Yes, in addition to purchasing and expanding operations at a former Cadbury facility in Hazleton, Pennsylvania, HFC has built additions on its Y&S Candies plant (licorice) in Lancaster, the H. B. Reese Candy Co. in Hershey, the new West Hershey plant, which is a milk processing and manufacturing operation, two (2) new, large scale product distribution centers in the Mechanicsburg and New Kingston area, and finally, HFC's new Corporate Headquarters/Data Center Complex in Hershey.

Because of these commitments, HFC (United States) now purchases more than 60% of its electric power from PP&L.

Q. What would be the impact on HFC from PP&L's proposed rate increases?

A. A majority of HFC's facilities are purchasing power under PP&L's LP-5 (firm) rate. HFC also has two (2) LP-4 (firm) and two (2) GS-3 accounts. As stated above, PP&L supplies more than 60% of the electricity purchased by HFC in the United States.

Because HFC, as a corporation, is so densely settled in PP&L's services territory, rate increases have a significant negative impact on operational costs. PP&L's new rate proposals would increase HFC's costs by approximately $2,000,000 per year, at HFC's current level of use.

Q. Does HFC utilize either of PP&L's economic development initiatives (EDI or IDI) to lower its electric rates to levels comparable to other electric utilities?

A. Yes, HFC currently receives the benefits of EDI and IDI at a value of approximately $1,500,000 per year based on the incremental growth of electric use at the above-mentioned facilities. This expense savings allows HFC to make other capital investments to continue to grow in an ever increasing competitive environment.

The plant managers at HFC's Pennsylvania facilities view their participation in these programs (EDI or IDI) as their way of achieving comparable electric rates to those that their sister plants are paying on straight retail tariffs in Virginia.

Q. **Why are comparable electric rates important to HFC's manufacturing plants?**

A. Although HFC does purchase most of its electricity in PP&L's service territory, it has other comparable operations served by Metropolitan Edison Company and many others outside of Pennsylvania. As in any business, new capital investment is directed to those areas where the probability of the return on that investment is greater. HFC is constantly assessing its manufacturing costs and other synergies, at every facility, to determine where its next investment should be made. Each manufacturing facility is in, more or less, competition for the next production line investment. A new production line translates into jobs, facility vitality and longevity. The proposed $2,000,000 per year increase puts HFC's Pennsylvania facilities at a further disadvantage at receiving significant future investments. This is why HFC has joined

PPLICA to state its opposition to PP&L's significant and detrimental rate increase proposal.

Q. Does this complete your testimony?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

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INFO. CONTROL DIV.

DIRECT TESTIMONY AND EXHIBITS OF

ROBERT K. FELTER

ON BEHALF OF THOMSON CONSUMER ELECTRONICS

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF ROBERT K. FELTER

ON BEHALF OF THOMSON CONSUMER ELECTRONICS

Q. Please state your name and business address.

A. My name is Robert K. Felter and my business address is Thomson Consumer Electronics, 200 Keystone Industrial Park, Scranton, PA 18512-4511.

Q. Please provide a brief educational and employment history.

A. I'm a graduate of Lehigh University with a Bachelor of Science Degree in Chemical Engineering. Twenty-seven years of my 36 years of employment experience have been in manufacturing operations. During the last 11 years, I've been specifically involved in the manufacturing operations of television picture tubes. For the last four years, I have served as the manager of Thomson Consumer Electronics, Scranton, Pennsylvania plant.

Q. What Thomson Consumer Electronics facilities are located in the service territory of Pennsylvania Power & Light Company?

A. Thomson has facilities located in Scranton, Lancaster, and Harrisburg, Pennsylvania, all within PP&L's electric utility service territory. Our primary facility in Scranton employs approximately 1,250 individuals. Our Lancaster facility employs an additional 230 people and our Harrisburg facility employs an additional 120 people. Thus, Thomson's total Pennsylvania employment in PP&L's service territory is 1,600.

Q. Please describe Thomson's manufacturing facility in Scranton, Pennsylvania.

A. Attached as Exhibit RKF-1 is a 2-page brochure describing Thomson's Scranton facility. The facility utilizes electric power for several thermal tube manufacturing processes and for all production equipment and automation. Substantial quantities of electricity are also used for plant refrigeration equipment needed for process cooling and critical factory temperature controlled environments. These production and process uses are in addition to the standard lighting and general service application uses for electricity.

Scranton plant consumes in excess of 90 million kWh per year and purchases service from PP&L pursuant to Rate Schedule LP-5 - Optional Interruptible Power.

Q. **What impact does the Scranton facility have on the local and state economy?**

A. With an employment level of 1,250 individuals, we estimate that the total financial impact on local community wages and benefits approximately $90 million per year with total expenditures by Thomson's Scranton facility totaling $270 million per year. In immediate local purchases alone, the facility expends nearly $18 million per year.

Q. **What type of products are manufactured at Thomson's Scranton facility?**

A. Our Scranton facility manufactures over 8,000 color TV picture tubes daily. Since the construction of the facility in 1966, the plant has manufactured over 35 million color TV tubes. One in every 11 large tubes manufactured worldwide is made in Scranton, Pennsylvania. A diagram of our product is included on page 2 of Exhibit RKF-1.

Q. Who are Thomson's primary competitors nationally and internationally in the manufacturing of color TV picture tubes?

A. Other picture tube manufacturers in the United States include Phillips, Zenith, Toshiba, Sony, Matsushita, and Hatachi. Even within Thomson Consumer Electronics, the Scranton, Pennsylvania facility's cost of electricity is higher than the sister plants in Marion, Indiana, and Circleville, Ohio. In addition, Thomson owns a picture tube manufacturing facility in Mexico City, Mexico.

Q. What type of economic contribution does Thomson make to the greater Scranton area?

A. Our compensation and benefit package for the 1,200 employees at the Scranton facility totals $65.8 million per year. We average capital expenditures on new plant and equipment of about $9.5 million per year with approximately 10% of that amount purchased from local entities. Our direct material costs are approximately $166.9 million per year, again, with approximately 10% of those direct materials being purchased locally.

Q. **What type of service does Thomson purchase from PP&L?**

A. Thomson purchases electricity from PP&L pursuant to Rate Schedule LP-5 - Optional Interruptible Power. Thomson chose to switch to interruptible power in order to keep the Scranton plant competitive within Thomson's sister facilities as well as with its non-affiliated competitors. Our Circleville, Ohio facility is served by Columbus Southern Power and we purchase firm electricity at an average price of approximately 4.3¢ per kWh. Our Marion, Indiana facility also purchases firm power at an average rate of approximately 4.1¢ per kWh. In order to obtain a comparable rate from PP&L, Thomson needed to convert from firm service to interruptible service because the LP-5 firm rate was averaging approximately 5.2¢ per kWh prior to our switch to interruptible service.

Q. **What is the potential impact on Thomson if PP&L's proposals are accepted by the Commission?**

A. As an LP-5 - Optional Interruptible Power customer, Thomson could experience an increase as high as 28% if PP&L receives its entire requested rate increase. Rather surprisingly, we also understand that even if PP&L receives no portion of its requested increase, the increase to the LP-5 - Optional Interruptible Power customers will be 22.46%. Increases of this magnitude will cause our Scranton plant's electric rate to be higher than our sister plants in Circleville, Ohio, and in Marion, Indiana, as well as with the other national and international competition mentioned earlier in my testimony.

Q. **How can the Commission elevate the adverse competitive consequences of PP&L's proposal on Thomson?**

A. As a member of the PP&L Industrial Customer Alliance, Thomson is also sponsoring testimony submitted by J. Kennedy and Associates, Inc. in this proceeding. We urge the Commission to adopt the recommendations contained in that testimony and contribute to a more competitive environment for Pennsylvania industry as that competition relates to electricity pricing.

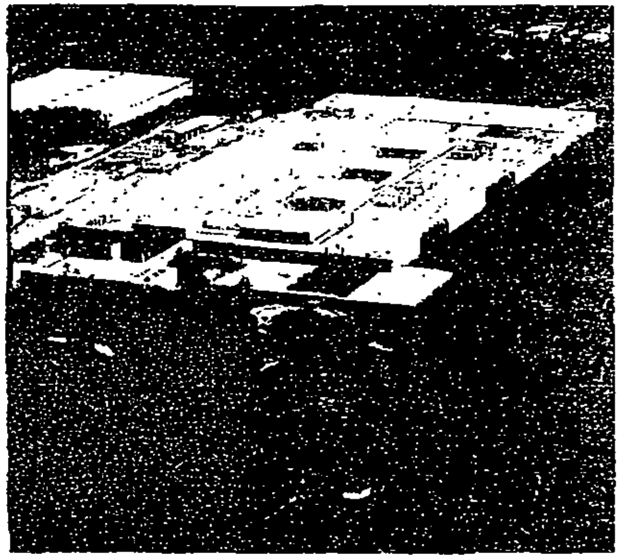
Q. **Does this complete your testimony at this time?**

A. Yes. Thomson appreciates having the opportunity of submitting this testimony to the Commission.

WORLD CLASS QUALITY

Thomson Consumer Electronics

Scranton, PA



Quality Policy

**WE, THE PEOPLE OF THOMSON NATD,
WORKING TOGETHER,
WILL MEET OR EXCEED
OUR CUSTOMERS' EXPECTATIONS
FOR QUALITY, RELIABILITY AND SAFETY
IN EVERYTHING WE DO.**

What is World Class?

A. Meeting and exceeding our customers' expectations (both internal and external) in terms of:

- product quality
- cost
- delivery
- service

We are Customer Driven!

B. Using all of our resources to continuously improve our performance. Our resources include:

- people
- materials
- technology

C. Continuous improvement to our systems and processes to minimize variation and to assure our customer that we provide the BEST product possible. These systems include:

- Safety
- Productivity
- Total Quality
- ISO 9000
- Manufacturing Resource Planning (MRP II)
- Statistical Process Control (SPC)
- Quality Leadership Process (QLP)

During 1993, Scranton became certified ISO 9002. This certification is a global recognition that Scranton operates within a quality system.

The Quality Leadership process is the cornerstone of TCE's global quality structure. At the heart of the process are QLP teams – groups of employees who tackle quality issues, both large and small, right where they are happening. Scranton's winning Quality Leadership Team symbolizes our commitment to quality.

Problem Busters QLP Team

"Success in today's business environment demands getting the basics right. It also requires the will to win – what we call Winning Spirit . . ."

Alain Prestat
Chairman and CEO

EXHIBIT RKF-1
Page 1 of 2

Thomson Consumer Electronics manufactures and markets home entertainment products world wide – products which connect us to one another. They inform, educate, and entertain.

The Company

TCE is the largest consumer electronics Company in the U.S. and the fourth largest in the world
Over 18,000 employees in the Americas in consumer electronics
Over 1,200 people are employed, across three shifts, at Scranton with an average of over 18 years of service.

The Facility

The main building occupies 480,000 sq. ft.
Other buildings 120,000 sq. ft.
The plant site 92 acres
Plant construction January 1966
First tube December 1966
First and second major expansions: 1969 and 1971
Over 3.5 miles of conveyor systems
Financial impact on local community wages and benefits $90 million
Total expenditure of TCE Scranton $270 million

Approximate Annual Services	
Electric	90 ~~27~~,000,000 k Whr
Natural Gas	373 million cubic ft.
Water	182 million gallons
Compressed air	390,000 cubic ft./hr.
Steam	18,000 lbs/hour
Cooling Capacity	3,600 tons

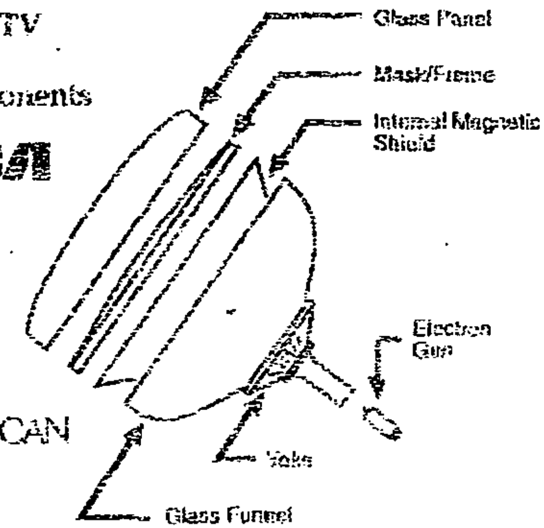
The Product

Color TV Tube Components

RCA

GE

PROSCAN



- Over 8,000 color TV picture tubes are manufactured daily
- It takes over 24 hours from raw goods to finished product
- Over 6,700 tons of steel and 61,000 tons of glass are used annually in producing TV picture tubes
- Finished goods are used in the U.S., Europe, South America the Far East and Antarctica
- One in every 11 large tubes (world-wide) are made at this location
- About half of the production is used by other TV manufacturers
- The Scranton Plant manufactured over 35 million color TV tubes since 1966.

Safety and Health

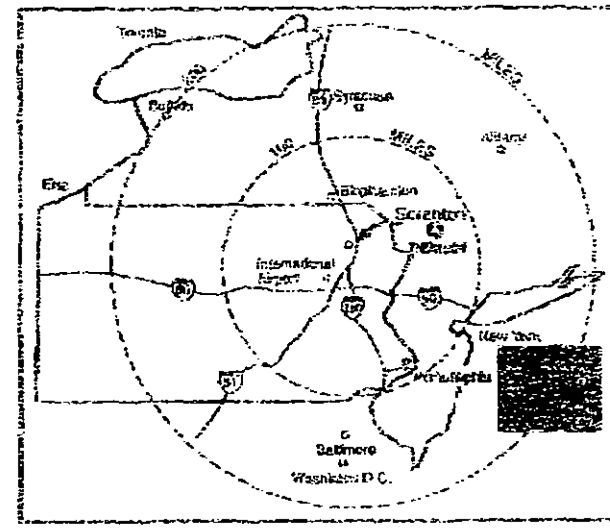
TCE is committed to providing a safe and healthy work environment for all employees. Emphasis is placed on safety program ownership and responsibility at every level of the organization. TCE is dedicated to improving the environment.

New Technology Market

Cinema Screen TV (A wide-screen 16 by 9 aspect ration vs. today's standard of 4 by 3)

High Definition TV with advanced features including digital video picture and digital CD quality audio

Digital Satellite System (small 18" fixed dish with over 150 channels)



The success story of the Scranton Plant over the years is a tribute to the many fine employees working at this facility. Scranton offers a high tech environment with an opportunity for people to advance. These outstanding employees and the country's most popular brands make Scranton a great place to work

An Equal Opportunity Employer

Thomson Consumer Electronics
200 Keystone Industrial Park
Dunmore, PA 18512
Phone: (717) 346-7771
Fax: (717) 969-5497

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF

JAMES H. ROONEY

ON BEHALF OF ARMSTRONG WORLD INDUSTRIES, INC.

A MEMBER OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF JAMES H. ROONEY

ON BEHALF OF ARMSTRONG WORLD INDUSTRIES, INC.

Q. **Please state your name and business address?**

A. My name is James H. Rooney and my business address is 2500 Columbia Avenue, Lancaster, PA, 17604.

Q. **On whose behalf are you appearing in this proceeding?**

A. I am appearing on behalf of Armstrong World Industries, Inc. which is participating in this case as a member of the PP&L Industrial Customer Alliance.

Q. **What position do you hold within Armstrong World Industries, Inc.?**

A. I am the Manager of Engineering and Energy Purchasing. In that capacity, I am responsible for the purchases of natural gas and electricity at Armstrong plants within the United States. For a complete description of my educational and professional background, see my resume attached hereto as Exhibit No. JHR-1.

Q. Please provide a brief description of Armstrong's facilities served by PP&L.

A. Armstrong has numerous facilities in PP&L's service territory. There are three facilities that would be dramatically affected by PP&L's requested rate increase. The first is Armstrong's Lancaster plant. This plant employs approximately 1,800 people and makes resilient flooring materials.

The second plant is our Marietta plant. It employs approximately 500 people and makes commercial ceiling and wall products.

Armstrong's third major facility is our Innovation Center. We have corporate research, engineering, styling and miscellaneous staff functions at this facility. The Innovation Center employs approximately 600 people.

Q. What would be the cost impact to Armstrong at these three facilities if PP&L receives their requested rate increase?

A. In 1994, Armstrong paid PP&L approximately $9,000,000 for electric service at these three facilities. PP&L's requested increase represents a 33% increase to the Marietta facility, a 30% increase to the Innovation Center, and a 25% increase to the Lancaster plant. These increases are unexpected and we believe unnecessary and excessive.

Q. Did PP&L talk to Armstrong about its requested rate increase prior to making the filing at the Pennsylvania Public Utility Commission?

A. No. PP&L did not come to us prior to filing the increase despite the fact that Armstrong has been very proactive in informing PP&L that it needs competitively priced electricity. We also told PP&L many times that Armstrong needed PP&L's interruptible rate to make the price of electricity at Lancaster, Marietta, and the Innovation Center competitive. We have also told PP&L that if they increased the Optional Interruptible Power rate disproportionately, we would be faced with the necessity of finding lower cost alternative sources of electricity.

Q. In what forums did you present this information to PP&L about your need for competitively priced electricity?

A. Two particular forums were used. First, we had specific individual meetings with PP&L representatives. These meetings included the local PP&L representative, middle management, and corporate management groups. One such example of this type of meeting was when we signed the Optional Interruptible Power rate agreement for Lancaster and Marietta. Armstrong had a luncheon meeting with PP&L

where Mr. Frank Long and Mr. John Seger, two vice presidents at that time, were present. One of Armstrong's vice presidents and plant managers from the Marietta and Lancaster plants were also present. At this luncheon meeting, Armstrong emphasized the need for competitive electricity and that our need for competitive electricity was why we were signing the Optional Interruptible Power rate agreement.

The second forum we used was PP&L's Large Customer Advisory Panel (LCAP). At LCAP meetings, I and others specifically and repeatedly told PP&L that we needed competitively priced electricity in PP&L's service territory. It was ironic that when PP&L was filing this base rate increase notice under seal with the Commission, PP&L was having an LCAP meeting with its largest industrial customers on the very same day. At no time during that meeting did they mention even the potential for a rate increase. We were totally caught off guard and totally surprised by PP&L's requested increase.

Q. **Is the timing of PP&L's proposed base rate increase logical to you?**

A. No. Given the internal reorganization and internal cost cutting efforts currently underway at PP&L, we were also surprised by the timing of this base rate increase. PP&L, for instance, has just required each one of their marketing people to reinterview for their jobs and many have lost jobs, have been moved or reduced in position. Also, the marketing and rate group has just been redesigned and reorganized.

Q. Why is PP&L doing this at a time when they are filing such a significant rate increase?

A. I don't know. PP&L is reorganizing and eliminating employees at one end and dramatically increasing rates to their customers at the same time. My opinion is that they are feeling the pressure from investors. We at Armstrong feel this pressure also, and we are also trying to increase our revenue and reduce our costs. However, it appears from the testimony which I have seen that PP&L is trying to raise revenue by claiming that it is cost driven. It is unfortunate because I believe that PP&L has been a credible utility up until recently and has worked with their customers to maintain that credibility. I know that PP&L has lost a lot of credibility with me over this rate increase and other recent events.

Q. Based upon your knowledge of the marketplace, are there any other reasons PP&L might be requesting this increase?

A. I believe that many utilities are trying to increase their rate base to prepare for deregulation. As an example of how this might work, PP&L is seeking to include Susquehanna II into their rate base. When deregulation arrives, and if Susquehanna Unit II is considered used and useful, it would be more likely to be subject to any future transition cost recovery. I believe many utilities across the country are looking for legitimate ways to get as much into rate base as they can. Then they can more likely recover it through transition costs as we move into a more competitive market. From the testimony presented by OCA witness Kahal, I don't feel that PP&L's request for adding Susquehanna Unit II to their rate base is justified.

Q. Why doesn't Armstrong just accept the increase and pass it along to your customers?

A. Armstrong cannot pass an electric rate increase along to our customers. We cannot add a charge to our bills to our customers to reflect electric cost increases that were unexpected by us. We will need to offset these increases in some way.

Q. How will Armstrong attempt to offset these PP&L increases if they are granted by the Public Utility Commission?

A. We will attempt to reduce the impact of these increases in two ways. First we will look for alternative suppliers of electricity and alternative ways to provide electric energy.

This will be similar to the way Armstrong offsets raw material increases or other price increases when we feel they are excessive and not market driven.

Second, any increases of the magnitude proposed by PP&L will *increase our direct costs of producing ceilings and floors* at our plants served by PP&L. One way to mitigate an increase of this magnitude is to shift manufacturing to other Armstrong facilities around the country that have lower direct costs.

Q. **Please explain specifically how you could implement these two methods to minimize the impact of any increases granted to PP&L if the increases are, in Armstrong's opinion, excessive?**

A. First, let us look how Armstrong will attempt to find alternate suppliers of electricity and alternate ways to provide electrical energy. At our Marietta ceiling plant, we know of at least three options we will investigate. First, we will determine whether another utility that is close to our Marietta plant can provide service at a more competitive price. Second, we will study whether we can form a municipal utility in the Borough of Marietta. We are looking at municipalization in several other places in the country where electric costs are high. Third, we would reactivate our cogeneration study. We already know that

Marietta is a prime candidate for a small combustion turbine. They have an excellent heat balance and the waste heat from the turbine can be directly used in Marietta's process. A turbine and self-generation also makes our operations more dependable and truly gives us two sources of power.

At our Lancaster plant, we would also look at the possibility of municipalization. At Lancaster we would try to bring other industrial customers together to form an alliance and provide electricity to that industrial alliance. Industry is not going to stay complacent in the increasing competitive world of electricity when we are faced with excessive prices by our local utilities. In areas where we cannot obtain competitively priced electricity from a utility, Armstrong will act as a catalyst to organize industry where it is necessary to achieve lower electric costs. Also at Lancaster we will reactive their cogeneration study. The magnitude of any increase will determine whether or not cogeneration is competitive.

Q. **Why do you think that these alternate forms of electricity are more competitive than PP&L?**

A. Let me provide some data.

TABLE 1

Annual Electricity costs	Lancaster & Marietta
PP&L's Proposed Rates with 100% Firm Service	$9,460,000
PP&L's Proposed Rates with Current Firm/Interruptible Mix	$8,998,000
PP&L Current Rates with Current Firm/Interruptible Mix	$7,280,000
PP&L 1/1/96 Wholesale Rate to Municipalities with Armstrong Load Characteristics	$6,677,000
Cogeneration First Year Cost With 15 Year Amortization	$5,706,000

The first line of Table 1 shows the combined annual charges that Armstrong's Lancaster and Marietta plants would pay to PP&L for firm power if PP&L's rate request is granted. the second line represents what Armstrong would pay for our current mix of firm and interruptible power if PP&L were granted their full increase. And the third line represents what Armstrong pays today for a year of electricity from PP&L at PP&L's current rates at Armstrong's current interruptible contract with PP&L.

The last two lines of Table 1 show two competitive alternatives that Armstrong has available to obtain power from alternate suppliers or in alternate ways. Line 4 is particularly concerning to me. It represents the cost that would be charged by PP&L to two municipals that are exactly the same size as Armstrong's Lancaster and Marietta plants and are in PP&L's service territory. Please note that this line represents the decrease in price PP&L is giving to their wholesale customers in their service territory on January 1, 1996. If Armstrong were one of those customers, we would be paying $2,321,000 less than PP&L is proposing we pay with their rate request, and we would be receiving firm power. That is we are paying 35% more as a captive customer for inferior interruptible service than we would as a whole customer with firm service. Why is this? How can this be fair?

Line 5 in Table 1 shows our year one price of electricity including amortization costs for a cogeneration facility. To realize this savings, one cogeneration system would be installed at Lancaster and one at Marietta.

Q. **Why did you choose this particular wholesale customer group to compare with Armstrong's costs of electricity?**

A. I chose this group because they represent PP&L's competitive marketplace and really should be the benchmark for competitive electricity to captive customers. In no case should Armstrong be paying a higher price for interruptible electricity, an inferior product, than what PP&L currently charges municipal customers for firm power. These municipals offer PP&L no less difficulty in service than Armstrong would be and are on PP&L's service territory. It is also interesting to note that the municipalities also have a much higher demand charge and only one energy charge block other than the demand charge blocks. Query why there is only one energy charge block for the municipal rate and no load factor implication.

Q. Why do you think municipal utilities might offer an advantage to Armstrong?

A. When a town has a municipal utility and wishes to attract business, they can, in essence, sell their electricity to the business or industry without profit and their town sees no penalty as a result of that. As a matter of fact, the town receives the additional business associated with the employees who are then employed by that local business or industry. If the town elects to sell electricity at a reduced cost to existing local business and industry, it helps the business be more competitive and helps other businesses realize that this town views business and industry in a favorable way. Also, citizens from within the town can pay the same rates as they would pay their local utility and the city or town is able to use profit from the sale of electricity to reduce the citizens' tax rate. This is a true win/win situation for the municipality, business, and the citizens.

Q. **What happens to these municipals and their revenue after retail wheeling takes place? Won't industry just leave them?**

A. Industry will make changes based upon cost reduction opportunities and contracts that they have with their suppliers. However, if industry has elected to enter a long-term agreement with a municipality, industry would be bound by that contract. If Armstrong establishes relationships with the cities that may support us through municipalization, we will view this as long-term relationship.

Municipalities could, in fact, become our agents of the future. Municipalities could still make profit from the electricity they sell to us by buying larger blocks of electricity and redistributing it to us. This is very similar to what gas marketers do in the natural gas industry. The marketers go into the marketplace, buy the gas, sometimes rebundle it with transmission and then ship it to us. Our local gas utilities distribute it and make a profit also. This could be the electric municipal's role of the future. The municipal could become the broker and the transporter, and redistribute electricity to us as gas utilities and marketers sell and distribute gas to us today.

We see relationships with municipalities as potential long-term relationships because Armstrong does not want to be in the electric supply business. We want somebody to do it for us, but we want that person to do it at competitive prices.

PP&L will not be competitive with their requested increase. They are making the cost of electricity that we buy from PP&L uneconomical with other choices. Armstrong must find those other choices and implement them. We regret that PP&L proposes to charge their native load customers who are tied to them and depend on them such a disproportionate premium. What makes it even less palatable is that PP&L is raising our prices at the same time they are reducing the price of electricity they sell to their non-captive wholesale customers on January 1, 1996.

Q. **You mentioned a second way Armstrong might mitigate the impact of a large PP&L increase would be to shift production to other Armstrong plants outside of Pennsylvania. How would this happen?**

A. This shift in production could occur in two ways. First, Armstrong could decide to expand and add new production capabilities to other locations around the country. Second, Armstrong can make many existing products at several locations. The choice of where to produce and ship from is based on many parameters. One parameter is direct cost.

The large increase that PP&L is proposing will increase Armstrong's direct costs to produce floors and ceilings in Lancaster County, and our Marietta and Lancaster plants compete with other Armstrong plants around the country.

Marietta competes primarily with four other Armstrong ceiling plants in Mobile, AL; Macon, GA; Pensacola, FL; and St. Helens, OR. The cost for electricity at these four plants in 1994 was 4.2¢/kWh, 5.0¢/kWh, 4.3¢/kWh, and 4.6¢/kWh. It needs to be emphasized that these prices are primarily for <u>firm</u> power. If Marietta had not taken the lower quality interruptible power from PP&L, its costs for power in 1994 would have been 5.5¢/kWh. For Marietta to compete with these other Armstrong plants and other reasons, it elected to take interruptible service for its production operation. If PP&L calls for an interruption, Marietta must shut down all of its production facilities.

Please also note that Armstrong's non-Pennsylvania facilities are decreasing their electric costs. Pensacola has already implemented a change in their electric supply which will reduce their cost by at least 12% for 1995. Macon, Mobile, and St. Helens are all looking at ways to further reduce their electric costs. These reductions and potential reductions will even further exaggerate the differential between electricity at Marietta and non-Pennsylvania Armstrong ceiling plants.

The Lancaster plant is a very old plant and makes many types of flooring products. It competes with several plants in the same way Marietta competes. The Lancaster plant, because of cost pressures, accepted PP&L's inferior quality interruptible service to reduce their costs. Lancaster is willing to interrupt production and deal with all the production problems associated with that interruption in order to reduce our electricity costs. We have accepted these interruptible hardships to reduce our costs and keep business in Lancaster County. Armstrong plants compete feverishly with each other to ship product to our customers. All plants are looking for ways to reduce their direct costs, and electricity is one of those costs.

Q. How can the PUC help Armstrong control their electric costs, be responsible to PP&L, and keep as much business in Pennsylvania as possible?

A. First, I am sure that the PUC will look at the revenue requirement requested by PP&L and see that it is excessive. Second, no matter what increase is granted, no customer should be forced to see an increase of the magnitude requested by PP&L from Armstrong. It is unreasonable for Armstrong to receive large increases when other non-captive wholesale customers of similar size to Armstrong are seeing cost reductions. Also, I ask the PUC to cap any rates charged by PP&L to any captive customers. For Armstrong, the cap should be same as PP&L charges non-competitive customers that have choices. We should pay no more for firm power, much less interruptible power, than PP&L charges their PP&L wholesale customers for firm power. That would be a fair way to handle pricing of captive customers until full retail competition is realized. If this is not done, captive customers will be hurt in two ways. First, their rates will be higher than non-captive customers with choices. Second, captive customers will help cover PP&L's cost of off-system sales made at prices below PP&L's cost of several energy purchases by paying PP&L through the ECR. What an unfair double hit.

Q. **Does this complete your testimony at this time?**

A. Yes, it does.

JAMES H. ROONEY
347 South Cope Hill Drive
Manheim, PA 17545
Telephone: (717) 665-2489

EXPERIENCE

1968 To Present ARMSTRONG WORLD INDUSTRIES (CORPORATE OFFICES)

Manager, Engineering and Energy Purchases (1991-Present)
Directs energy procurement for 37 plants. Annual budget of $80 million includes responsibility for energy strategies, suppliers and negotiations. Cost reductions implemented in 1994 will exceed $3 million. In 1993 received a General Manager's Award for gas savings exceeding $1.8 million while implementing FERC-Rule 636 at Armstrong's plants. National speaker for natural gas issues regarding FERC-Rule 636 and industrial energy strategies.

Purchasing Manager-Engineer and Energy Purchases (1989-1991)
Directed energy procurement for 14 plants and capital procurement for Floor Division. Annual budget of $85 million. Cost saving exceeded $2.0 million per year including $1.1 million in savings for gas purchases in the Carpet Division. In 1990 received a General Manager's Award for a BTU conversion that saved $1.6 million and a Manager's Award for contractor negotiations on disputed charges exceeding $500,000.

ARMSTRONG WORLD INDUSTRIES (MARIETTA PLANT)

Purchasing Manager (1984-1989)
Managed department of 5 with $40 million annual budget for raw materials and MRO purchases. Led multi-discipline waste reduction team that reduced waste disposal costs by $650,000. Budgeted and achieved purchase savings in excess of $500,000 new savings each year. Changed department from administrative focus to value added focus. Developed and implemented on-line computer purchase order system then used by other plants. Initiated SQC for raw materials, JIT direct release for repetitive items, and invoiceless payment system. Received Manager's Award for multi-plant calcium carbonate negotiations.

ARMSTRONG WORLD INDUSTRIES (CORPORATE OFFICES)

Purchasing Manager-Systems Components (1980-1984)
Managed $45 million procurement of major raw materials and components where Armstrong represented a large percentage of suppliers' output. Developed tooling programs, negotiated prices, and coordinated vendor cost reduction programs to specifically reduce the cost of products purchased by Armstrong. Production line speed increase and gauge reduction of ceiling grid saved in excess of $600,000 the first year. Built dockside warehouse and imported bulk shiploads of a raw material that saved $1.2 million annually. Presented negotiation seminars for Armstrong's marketing representatives.

Purchasing Coordinator-System Components and Accessories (1977-1980)
Managed $7 million procurement of specially designed grid, lighting and air distribution systems resold by Armstrong. Purchasing/production representative on Armstrong "Vendor Product Development Steering Committee." Implemented formal cost reporting and measurement system.

Purchasing Agent-Jobbed Products (1976-1977)
Managed $4 million procurement of miscellaneous jobbed products resold by Armstrong. Negotiated price, delivery, and coordinated efforts of plants distributing purchased items.

ARMSTRONG WORLD INDUSTRIES (CENTRAL ENGINEERING)

Project Engineer-Furniture Operations (1975-1976)
Special Assignment to coordinate multi-discipline effort to solve lumber handling problems at Thomasville Furniture. US Patent 4,220,115 issued.

Product Engineer-Corporate Projects (1972-1975)
Engineered new modular furniture product lines for special president's office project. Engineering/production representative to 5 person task force responsible to develop a new plant for modular furniture lines. College Recruiter for Engineering graduates.

Engineer (1969-1971)
Led efforts to engineer and install $4 million integrated additives handling process at new plant. Developed new process for roof insulation manufacturing and installed $1.5 million systems that saved over $2 million per year from previous concept. Led effort to integrate textile production through automation of labor intensive mechanical processes.

Engineer in Training (1968-1969)
Machine design including layout and detailed design. Assisted other engineers on their projects.

EDUCATION MBA-Lebanon Valley College, 1993

BSME-University of Delaware, 1968
Major: Mechanical and Aerospace Engineering

PPLICA CROSS-EXAMINATION
EXHIBIT NO. 8

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4-26-95
PUBLIC'S EXHIBIT 10 Hg

R-943271

DOCKETED
APR 28 1995

STATE OF INDIANA

DOCUMENT FOLDER

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY FOR THE APPROVAL OF PERMANENT RATES AND CHARGES FOR ELECTRIC SERVICE, NEW SCHEDULES OF RATES AND CHARGES, AND RATES AND REGULATIONS APPLICABLE TO SUCH RATES AND CHARGES)	CAUSE NO. 39314

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INFO. CONTROL DIV.

DIRECT TESTIMONY OF

DR. CHARLES E. JOHNSON

ON BEHALF OF

THE INDIANA OFFICE OF

UTILITY CONSUMER COUNSELOR

SEPTEMBER 24, 1992

EXETER
Associates, Inc.

10801 Lockwood Drive
Suite 350
Silver Spring, MD 20901

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STATE OF INDIANA

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY FOR THE APPROVAL OF PERMANENT RATES AND CHARGES FOR ELECTRIC SERVICE, NEW SCHEDULES OF RATES AND CHARGES, AND RATES AND REGULATIONS APPLICABLE TO SUCH RATES AND CHARGES	)	CAUSE NO. 39314

DIRECT TESTIMONY OF

DR. CHARLES E. JOHNSON

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 10801 Lockwood Drive, Silver Spring, Maryland, 20901.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a combined B.S. Degree in Chemistry and Physics from the University of Utah, an M.S. in Mathematics from the University of Wisconsin, and a Ph.D. in Mathematics from the Ohio State University.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE RECEIVING YOUR DEGREES?

A. After completing my graduate education, I was an Instructor of Mathematics at Kansas State University in Manhattan, and an Assistant Professor of Mathematics at Wichita State University. In 1974, I left the academic environment and was employed by Control Data Corporation as a Manager responsible for mathematical modeling. In 1977, I joined the economic consulting firm of J.W. Wilson & Associates, Inc. Since that time, I have been consulting in the area of energy economics and utility regulation. I became a principal of Exeter Associates, Inc. in January 1986.

(1) Production investment be allocated by the peak and average method, using the six monthly coincident peak demands for the demand component;

(2) If the peak and average method is not used to allocate production investment, the 12 CP method should be used; and

(3) The minimum distribution system approach not be used in allocating distribution costs.

With respect to the setting of class revenue levels, I make the following recommendations:

(4) Based on costs determined by a cost study performed as described above, 50 percent of class subsidies be eliminated, subject to the following constraints;

(5) No class receive a rate reduction;

(6) No class receive an increase greater than twice the overall increase; and

(7) The IRP class receive an increase 1.5 times the overall increase.

With respect to rate design, I make the following recommendations:

(8) No demand-side management (DSM) adjustment be made in developing rates;

(9) I&M immediately develop time-of-day (TOD) rates for its largest commercial and industrial customers, and be directed to prepare a plan for developing TOD rate options for other commercial and industrial customers; and

(10) I&M investigate use of rate forms other than the simple DEC rate form for non-residential customer classes.

I have also prepared a set of model rates for most of the I&M rate classes -- residential service, small general service, medium general service, large general service, quantity power and industrial power. I recommend:

(11) The model rates be used as a basis for developing final rates for I&M.

Bethlehem Steel St. 1
+ Exs MEB-1, 2+3

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Hrg
R-943271

Before the

Pennsylvania Public Utility Commission

Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY

DOCUMENT FOLDER

Testimony and Exhibit

of

MAURICE BRUBAKER

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On Behalf of

Bethlehem Steel Corporation

Project 6308
April 1995

Brubaker & Associates, Inc.
St. Louis, Missouri 63105-0840

PENNSYLVANIA POWER & LIGHT COMPANY

Before the

Pennsylvania Public Utility Commission

Docket No. R-00943271

<u>Direct Testimony of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker, 7730 Forsyth Boulevard, St. Louis, Missouri.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A My testimony is presented on behalf of Bethlehem Steel Corporation.

Q WHAT SUBJECTS ARE ADDRESSED IN YOUR TESTIMONY?

A In my testimony I address changes taking place in the utility industry, the level of PP&L's industrial rates and the need to offer competitive prices. I then address cost of service, revenue allocation and rate design issues. I have reviewed the evidence presented by Pennsylvania Power & Light Company (PP&L) in these areas, and, as a result of that review, have identified certain changes that are required to make the cost of service study more reflective of accepted cost-causation principles.

Q DOES YOUR TESTIMONY ADDRESS PP&L'S CLAIMED REVENUE REQUIREMENT?

A No. For purposes of my analysis, I have utilized PP&L's numbers with regard to revenues, expenses, rate base and other elements of its claimed revenue requirement. Use of PP&L's numbers is for the purpose of comparing the results of the application of appropriate cost allocation principles and should not be construed as an endorsement of PP&L's revenue requirement claim, or any component thereof.

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. The electric utility industry is undergoing a major transition from a regulated status to one which includes more competition from alternate supply sources. As the transition to a less regulated environment occurs, it is important that utilities offer competitive rates in order to reduce the risk of load loss and revenue erosion.

2. PP&L's firm industrial rates are high and non-competitive. Its interruptible rates are about in the middle of the rates surveyed under current rate levels, but near the top if PP&L's proposed rates were accepted. Acceptance of PP&L's proposed pricing for interruptible power would make its interruptible rates as uncompetitive as its firm rates.

3. PP&L has erroneously treated interruptible loads in its cost of service study. It allocates costs to these loads as if they were firm, and then makes only a token "credit" adjustment. PP&L's approach is at odds with generally accepted procedures, fails to recognize the long-term capacity planning benefits provided by interruptible load (as compared to firm load), and is short-sighted.

4. In determining the adequacy of the contribution which interruptible customers make to the utility, there should be no allocation of generation-related capacity costs to interruptible load. This approach appropriately recognizes the nature of interruptible load, and the fact that the utility does not plan to install capacity to serve it.

5. PP&L has inappropriately handled the Economic Development Initiative (EDI) and Industrial Development Initiative (IDI) credits. Its approach fails to recognize that these sales were intended to benefit all customers. PP&L's approach burdens the classes in which these customers reside with the full difference between the standard tariff rates and the economic development rates. This is inappropriate, and at odds with the intent of the program. A more appropriate approach is to allocate the revenue differential to all customer classes on the basis of non-fuel revenues.

6. PP&L has failed, in its cost of service study, to disaggregate payments to non-utility generators (NUG) into energy and capacity components. PP&L's treatment in its cost of service study is inconsistent with how revenues are collected through the Energy Cost Rate (ECR). To be consistent with the ECR, and to avoid distorting the results of the cost of service study, 16% of NUG payments should be classified as demand-related.

7. The cost of service analysis shows that when corrections are made for the above-described deficiencies in PP&L's cost of service study; customer classes containing interruptible customers (LP-4, LP-5 and ISA) have rates of return in excess of the system average rate of return at present (and also proposed) rates. Therefore, if the Commission determines that PP&L is entitled to any rate increase, the rates for customers in these classes should be increased less than the system average.

8. The design of existing rate schedule LP-5 is appropriate. There is no inherent benefit in the proposed LP-5 structure. I recommend that the existing LP-5 structure be retained, and that the existing price relationship between firm and interruptible service be maintained.

COMPETITION AND RATE LEVEL

Q IN YOUR OPINION, WHAT IS THE SINGLE MOST IMPORTANT TREND IN THE ELECTRIC UTILITY INDUSTRY TODAY?

A Without question, the single most important trend in the electric utility industry today is competition. Gone are the days when an electric utility could feel secure and protected from competition for its load by alternate supply sources. Within the retail market (i.e., excluding wholesale for resale services to municipalities and other resale customers), the greatest degree of competition exists in the large, energy intensive customer market.

Q **WHAT IS THE NATURE OF THE COMPETITION?**

A There is competition from qualifying facilities (QF) in the form of cogeneration, competition from other electric utilities who compete with PP&L for new loads and for relocation of existing loads, as well as for the allocation of industrial production among existing plants. And with the passage of the Energy Policy Act of 1992 (EPACT) and subsequent events, there is an increasing potential for direct competition via access to retail customer load by other electric utilities or producers of power.

Recent events suggest that the opportunities/threats of competition may increase faster than most observers had thought. I refer to the April 11, 1994 Decision of the Michigan Public Service Commission in consolidated Case Nos. U-10143 and U-10176, in which the Michigan Commission determined that it would be appropriate to conduct an experiment involving retail wheeling by large customers of Consumers Power Company and The Detroit Edison Company.

Also of substantial significance is the April 20, 1994 Order of the Public Utilities Commission of the State of California in R.94-04-031/I.94-04-032. This Order declares the California Commission's long-term vision of the electric utility industry as embodying the opportunities for competitive power supply sourcing by all customers. The California Commission has instituted a rule-making and investigation into these proposed policies and the industry restructuring necessary to implement them. In a bold move away from other major California utilities, Pacific Gas and Electric Company (PG&E) has prepared a time table for implementation of direct customer access, and asserted that direct customer access by means of bilateral contracting is preferable to the reforms at the wholesale level which are being espoused by the other major California utilities.

In the midwest, PSI Energy Inc. (now a part of CINergy) has declared an intent to provide the opportunity for competitive sourcing to its 40 largest customers. PSI is beginning to hold meetings with its large customers in an effort to determine how these opportunities can best be structured and implemented.

It was also recently announced that the Detroit Edison Company has signed a ten-year sole supplier contract covering the major manufacturing facilities operated in its service area by Chrysler Corporation, Ford Motor Company and General Motors Corporation. Public statements have indicated that the expected reduction from tariff rates is approximately 15% over the ten-year period.

Also, here in Pennsylvania the Commission has established an investigation into competition in the electric utility market (Docket No. I-940092), including specifically the potential for retail competition.

All of these events, and others, were unheard of just a few years ago. They clearly mark a major transition in the electric utility industry—one which will greatly expand options available to customers and put substantial pressure on the traditional suppliers of electric utility services. Utilities are finding that many customers have options that allow them to satisfy their electric power requirements at prices which are less than the traditionally calculated utility rates. Under such circumstances, and especially during the period of transition to a more open environment, consideration must be given to the benefit to the other customers and to the stockholders of the utility of retaining this competitive load. Many utilities offer rates that are less than the fully allocated cost of service, but above the level of the costs that would be avoided if the load were lost, in order to retain the load and maximize the contribution to fixed cost recovery.

Q **HOW DO PP&L'S INDUSTRIAL RATES COMPARE WITH THE RATES CHARGED BY OTHER UTILITIES?**

A PP&L's industrial rates are high and not competitive.

Q **WHAT COMPARISONS OF PP&L'S FIRM RATES HAVE YOU MADE?**

A I have compared PP&L's firm rates, at several kW levels and load factors, with the rates charged by other utilities in the industrialized states of Illinois, Indiana, Michigan, Minnesota, Ohio, Pennsylvania and Wisconsin.

This information is summarized on Exhibit MEB-1 (   ). As shown on Schedule 1, PP&L's rates are among the highest.

Q **HAVE YOU MADE AN HISTORICAL COMPARISON OF PP&L'S RANKINGS IN THIS SURVEY?**

A Yes. This is shown on Exhibit MEB-1 (   ), Schedule 2. Over the period 1981-1994 PP&L's relative competitive position has grown significantly worse.

Q **WHAT DO THESE COMPARISONS SAY ABOUT PP&L'S CURRENT COMPETITIVE POSITION?**

A This information clearly shows that the rates which PP&L charges for firm industrial power are not competitive. Being competitive means offering prices at or near the low end of the market, not at or near the high end of the market.

Q **HAVE YOU MADE ANY COMPARISONS OF THE LEVEL OF INTERRUPTIBLE RATES?**

A Yes. This is shown in Exhibit MEB-2 ( ). The load used for the analysis is the same 12,000 kW load for which firm power rate comparisons are made on Page 1 of Schedule 1 of Exhibit MEB-1 ( ), except that 1,000 kW of the total load has been designated as firm, with the balance treated as interruptible.

Q **WHAT DOES THIS COMPARISON SHOW?**

A This comparison shows that at present rates the price of interruptible power offered by PP&L is about in the middle of the 32 company comparison. At proposed rates, however, the comparison shows that PP&L's price for interruptible power would rank it fifth from the top—a position that is relatively <u>worse</u> than is true for PP&L's firm rates.

The obvious conclusion from this analysis is that the draconian proposals which PP&L has made for its interruptible power service substantially erode its competitive position.

CLASS COST OF SERVICE STUDY

Q **HAS PP&L PREPARED A CLASS COST OF SERVICE STUDY?**

A Yes. PP&L has submitted the results of several cost of service studies. The primary difference among the studies is the method used for the allocation of capacity costs. The methods submitted by PP&L include the 12 monthly coincident peak (12 CP) method, the average and excess demand (AED) method, and the winter coincident peak (Winter Peak) method. Of the three studies, PP&L has expressed a preference for the 12 CP methodology.

Q **DO YOU AGREE WITH PP&L THAT THE 12 CP METHODOLOGY IS PREFERABLE?**

A No, I do not. Based on PP&L's predominant winter peaking characteristics, I believe that a winter peak cost of service study would be more appropriate.

However, for purposes of my testimony, I will not take issue with PP&L's 12 CP study. Rather, I will use its preferred 12 CP study and demonstrate that even this study (which allocates more costs to industrial customers than would a winter peak study) shows that the industrial classes are producing rates of return substantially above system average when other flaws in PP&L's cost of service study are corrected.

Q **WHAT ARE THE PRINCIPAL FLAWS IN PP&L'S COST OF SERVICE STUDY THAT YOU WILL ADDRESS?**

A There are three principal flaws that I have identified. First, PP&L allocates costs to interruptible customers as if they were firm, and then provides a token "credit" almost as an after-thought. The result is that excessive costs are allocated to those classes of customers containing interruptible load.

Second, PP&L has improperly treated the revenue effect of EDI & IDI credits—effectively assigning the entire difference between full tariff revenues and the EDI/IDI revenues to those classes in which the EDI/IDI customers reside. This approach produces an artificially low rate of return for these customers, and leads to the anomalous result that a program designed to provide benefits to all customers winds up burdening the participating customers and other members of their classes.

Third, PP&L has inappropriately classified to the energy category 100% of the payments which it expects to make to non-utility generators (NUG). This is in direct contravention to the disaggregation of these payments into proxy demand and energy components which the Company has used in calculating ECR revenues. PP&L's treatment is inconsistent and produces a distorted result.

<u>Treatment of Interruptible Loads in Cost of Service Studies</u>

Q **IN ITS COST OF SERVICE STUDIES, HOW HAS PP&L TREATED INTERRUPTIBLE LOAD?**

A In allocating investment and expenses among customer classes, PP&L has treated interruptible load the same as firm load. No distinction is made with respect to the difference in quality of service between firm and interruptible power.

After the cost of service allocations have been made, PP&L then assigns a bogus investment "credit," equal to $300 per kW of investment, to interruptible load. These amounts are subtracted from the rate bases of the classes containing interruptible load.

Q **WHAT IS THE BASIS FOR THE $300 PER KW CREDIT?**

A According to PP&L it is an approximation of the cost of installing a combustion turbine (CT) peaking unit. Under PP&L's theory, the interruptible load is viewed simplistically as an alternative to the installation of CTs.

Q **IS IT APPROPRIATE TO VIEW INTERRUPTIBLE LOAD SIMPLY AS A SUBSTITUTE FOR THE INSTALLATION OF CTs?**

A No. PP&L's treatment of interruptible load is a short-sighted view. It also fails to recognize that interruptible load is a cost-based service offering.

Q **PLEASE EXPLAIN.**

A First, it is important to understand the nature of interruptible power. The designation "interruptible" means that the utility does not plan to supply the power to the customer with as much reliability or regularity as is true for customers subscribing for firm power service. PP&L does not include interruptible load in its peak load forecast and does not plan generation facilities to serve it. Therefore, interruptible load does not cause PP&L to incur any generation-related capital costs. Generation capital costs are incurred to provide firm service, not to provide interruptible service.

Power is made available to the interruptible customers when the system has the ability to serve firm load, plus has available additional capacity to provide service to customers who take service under the terms of the interruptible tariffs. If and when the power being supplied to interruptible customers is needed to supply the load of firm customers and/or to maintain system integrity, it is withdrawn from the interruptible customers. Curtailments during the cold weather periods in early 1994 are prime examples of the withdrawal of interruptible power from its subscribers in order to protect the service provided to firm service customers.

Another way to think of interruptible power is as an unbundling of the firm service, wherein the generation capacity (or reliability) component is removed from the service. In this sense, therefore, interruptible power may be thought of as a cost-based rate option which carries a lower price than firm power because it is of a lower quality.

Q **WHAT EFFECT DOES INTERRUPTIBLE POWER HAVE ON THE UTILITY'S SYSTEM?**

A It has a very positive effect. As compared to selling power on a firm basis, when the utility sells power on an interruptible basis it can avoid planning to install capacity to serve that portion of the load.

Q **IN PROJECTING ITS REQUIREMENTS, DOES PP&L SUBTRACT INTERRUPTIBLE LOAD FROM ITS TOTAL EXPECTED PEAK?**

A Yes. This is clearly evident in its annual Resource Planning Report (RPR) filings wherein PP&L subtracts its forecasted interruptible load from its projected system peak load.

In addition, Mr. Sipics testified at Page 11 of PP&L's Statement No. 9 that the most appropriate basis for assessing its reserve margins is the data in Exhibit JFS-1 which includes an adjustment to reflect the "capacity value" of interruptible load. In other words, PP&L treats interruptible as load for which it need not plan capacity.

Q **IS PP&L'S APPROACH, IN ITS CLASS COST OF SERVICE STUDY, OF ASSIGNING INTERRUPTIBLE LOAD A CAPACITY CREDIT EQUAL TO THE ESTIMATED COST OF A CT, A TRADITIONAL APPROACH?**

A No. In fact, the way that the credit is factored into the studies suggests that this particular approach was certainly not an integral part of PP&L's effort to develop a cost of service study based on the principles of cost-causation. In addition to the theoretical problems with the method, it is incomplete because there is no reflection of any avoidance of depreciation, taxes, or operation and maintenance expense.

Q **HOW ARE INTERRUPTIBLE LOADS TYPICALLY TREATED IN CLASS COST OF SERVICE STUDIES?**

A The typical and generally accepted approach is to not allocate generation capacity costs to loads which are interruptible. (Sometimes, transmission-related costs are not allocated to interruptible load either.) The theory of this approach is that the utility need not, and does not, plan to add capacity to meet interruptible load. This treatment of interruptible load recognizes that capacity planning is a long-term proposition. Over time, a utility adds a mix or combination of plants and/or purchases power, to meet its anticipated requirements at the lowest overall expected reasonable cost. Just as a utility does not install only one kind of generation plant, so too is it inappropriate to treat interruptible power as if it is a substitute just for CTs. PP&L's approach is an extremely short-sighted view, and creates a distorted picture of the role of interruptible power.

Q EARLIER YOU INDICATED THAT INTERRUPTIBLE POWER COULD ALSO BE THOUGHT OF AS AN UNBUNDLING OF FIRM SERVICE. PLEASE ELABORATE.

A Because of the differences in quality of service, interruptible power is essentially firm power with the generation reliability component removed. It provides customers an option as to the reliability of service for which they contract. The ability to select the appropriate quality of service provides an important option for customers. Most customers require traditional firm service, but some customers are able to utilize power that is of a lesser degree of reliability. In light of the very high level of PP&L's firm rates, it is especially important that reasonably priced interruptible service be made available in PP&L's service territory, as a necessary service to its energy intensive customers.

Q HAVE YOU PREPARED A COST OF SERVICE STUDY THAT PROPERLY TREATS INTERRUPTIBLE LOAD?

A Yes. My "adjusted" cost of service study removes the interruptible loads from the class demands used for purposes of allocating production system capacity costs. I have left the full amount of the interruptible loads in the demands used for the allocation of transmission and other capacity-related items, however.

Q HOW SHOULD INTERRUPTIBLE LOADS BE TREATED IN FUTURE COST OF SERVICE STUDIES?

A In future cost of service studies, interruptible load should be segregated in a separate class so its profitability can more clearly be determined.

<u>EDI & IDI</u>

Q **DOES PP&L OFFER ECONOMIC DEVELOPMENT INITIATIVE (EDI) AND INDUSTRIAL DEVELOPMENT INITIATIVE (IDI) CREDITS?**

A Yes. PP&L offers these credits in order to preserve existing load, or to attract new load to its system. These credits are currently received by customers in the GS-3, LP-4, LP-5 and ISA classes. The dollar amounts of the credits are shown on Schedule D-3 of Exhibit Future 1.

Q **HOW ARE THESE CREDITS TREATED IN THE CLASS COST OF SERVICE STUDY?**

A In developing the revenues in the class cost of service study, PP&L allows these credit amounts to reduce the revenues of the previously mentioned customer classes in which the customers receiving the credits reside.

Q **IS THIS AN APPROPRIATE TREATMENT OF THESE CREDITS IN A COST OF SERVICE STUDY?**

A No. The cost of service study allocates full costs to these loads and then, by subtracting the credits from the otherwise applicable rate, forces the entire effect of the difference between the regular tariff rates and the economic development rates onto the very customers receiving the economic development rates and other members of the classes of which they are a part. The lower rate of return produced for these classes as a result of PP&L's method then, in turn, is used to support larger increases for these classes of customers. This approach is inappropriate, and leads to the anomalous result that a program designed to provide benefits to all customers winds up burdening the participating customers and other members of their classes.

Q IS THE INTENT OF THE EDI/IDI PROGRAM TO PROVIDE BENEFITS TO THE PARTICIPANTS, WHILE MAKING OTHER CUSTOMERS BETTER OFF THAN THEY OTHERWISE WOULD HAVE BEEN?

A Yes. This is clearly stated in the direct testimony of PP&L witness Kaspar, at Page 18 of Statement No. 8. There, Mr. Kaspar explains that non-participating customers benefit from the presence of these rates because the revenues (at the reduced level) cover the marginal cost of providing the service and make a contribution to the recovery of fixed costs—resulting in lower fixed costs per unit of output. This is a beneficial result for the non-participating customers because it allows their rates to be lower than otherwise would have been possible.

Q HOW SHOULD THESE CREDITS BE HANDLED IN THE CLASS COST OF SERVICE STUDY?

A An appropriate treatment of these credits would recognize the purpose of the program which gives rise to the credit, and the fact that the resulting load makes all other customers better off than they otherwise would have been. The specific approach which will accomplish this result is to price out the participating customers at the level of the regular tariff (without discounts) and to spread the amount of the credit across all customer classes (including the classes containing the participants) on the basis of each classes' non-fuel revenue. This approach spreads the revenue effect of the credit across all customers and is appropriate because it is intended that all customers benefit from the availability of this program. In contrast to PP&L's treatment, my recommended approach does not create a built-in revenue deficiency for the classes of which the participants are members.

Classification of NUG Payments

Q IN ITS CLASS COST OF SERVICE STUDY HOW HAS PP&L TREATED PAYMENTS TO NON-UTILITY GENERATORS (NUG)?

A In its cost of service study PP&L has treated payments to NUGs as strictly energy related, and allocated the cost of these purchases across all classes on the basis of class energy consumption.

Q IS THIS CONSISTENT WITH HOW THESE COSTS ARE TREATED IN THE ENERGY COST RATE (ECR) FOR REVENUE COLLECTION PURPOSES?

A No. In the ECR the NUG payments are disaggregated into proxy demand and energy components using the PJM capacity deficiency rate for the capacity component. Details are shown on Page 10 of Schedule D-3 in Exhibit Future 1.

PP&L's treatment of these costs in the cost of service study is inconsistent with its treatment of these costs in the ECR.

Q WHAT PERCENTAGE OF THESE NUG PAYMENTS HAS PP&L CHARACTERIZED AS DEMAND-RELATED IN DEVELOPING THE ECR?

A Approximately 16% of the costs are demand-related, and approximately 84% are energy-related under this approach.

Q HOW SHOULD THESE COSTS BE TREATED IN THE CLASS COST OF SERVICE STUDY?

A 16% of these costs should be classified as demand-related and allocated to classes on the basis of the demand allocation factor. The balance should be classified as energy-related and be allocated using class energy relationships.

COST OF SERVICE STUDY RESULTS

Q WHERE DO YOU PRESENT THE RESULTS OF YOUR ADJUSTED COST OF SERVICE STUDIES?

A These are presented in Exhibit MEB-3 (   ). Schedule 1 presents the results at present rates, and Schedule 2 presents the results under PP&L's proposed rates.

Q WHAT OVERALL CONCLUSIONS DO YOU DRAW FROM THE COST OF SERVICE STUDY ANALYSIS?

A The cost of service study clearly shows that those customer classes containing interruptible customers (LP-4, LP-5 and ISA) have rates of return in excess of the system average rate of return at both present and proposed rates. This result establishes that when a proper cost of service analysis is performed, the customers in these classes are producing revenues in excess of their cost of service, and are in fact contributing benefits to other customer classes. Therefore, if the Commission determines that PP&L is entitled to any rate increase, the rates of customers in these classes should be increased less than the system average.

RATE DESIGN

Q HAVE YOU REVIEWED THE DESIGN OF RATE SCHEDULE LP-5 AT PRESENT AND PROPOSED RATES?

A Yes, I have. The present Rate LP-5 contains two separate rate statements and billing provisions, one for customers taking only firm service, and a separate provision for customers taking part of their service as firm and part as interruptible.

Q HOW DOES PROPOSED RATE LP-5 DIFFER?

A In proposed Rate LP-5 the billing provisions are consolidated, and the interruptible provision is a credit to be subtracted from the calculated bill under firm rates.

Q IS THERE ANY ADVANTAGE TO THE PROPOSED RATE STRUCTURE AS COMPARED TO THE STRUCTURE WHICH CURRENTLY EXISTS?

A No. The proposed rate structure has no inherent advantage over the structure of current Rate LP-5. Since the existing rate structure is perfectly acceptable, I recommend that it be retained. Any increase approved for Schedule LP-5 should maintain the rate relationships between firm and interruptible service that are in the current rate.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

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

A Maurice Brubaker, 7730 Forsyth Boulevard, St. Louis, Missouri.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, telephone and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income.

I have testified before the regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

We have prepared many studies relating to electric, steam, gas and water properties, including cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

During the past five years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 500 major utility rate cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, steam and telephone rates. Rate cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

In addition to our main office in St. Louis, the firm also has branch offices in Austin, Texas; Denver, Colorado; and Harrisburg, Pennsylvania.

PENNSYLVANIA POWER & LIGHT COMPANY

Comparison of Firm Power Cost for an Industrial Load of 12,000 kW, 68% Load Factor for the Year 1994

Line	Utility	Power Cost* for 1994 (1)	Mills per kWh (2)
1	Toledo Edison Company, The	$5,819,990	81.18
2	Philadelphia Electric Company	5,815,389	81.12
3	Cleveland Electric Illuminating Company, The	5,000,512	69.75
4	Ohio Edison Company	4,772,639	66.57
5	Detroit Edison Company, The	4,602,631	64.20
6	Duquesne Light Company	4,544,383	63.39
7	Pennsylvania Power & Light Company - Proposed	4,539,620	63.32
8	Northern Indiana Public Service Company	4,533,201	63.23
9	Pennsylvania Power & Light Company - Present	4,149,820	57.88
10	Pennsylvania Power Company	4,012,449	55.97
11	Commonwealth Edison Company	4,008,088	55.91
12	Illinois Power Company	3,990,925	55.67
13	Metropolitan Edison Company	3,946,474	55.05
14	Consumers Power Company	3,917,709	54.65
15	Central Illinois Public Service Company	3,673,295	51.24
16	Minnesota Power & Light Company	3,640,586	50.78
17	Pennsylvania Electric Company	3,622,714	50.53
18	Dayton Power and Light Company, The	3,577,747	49.90
19	Central Illinois Light Company	3,459,313	48.25
20	Cincinnati Gas & Electric Company, The	3,398,522	47.41
21	Indiana Michigan Power Company - IN	3,317,199	46.27
22	Northern States Power Company - WI	3,274,903	45.68
23	Union Electric Company - IL	3,009,744	41.98
24	West Penn Power Company	2,975,445	41.50
25	Wisconsin Public Service Corporation	2,948,888	41.13
26	Northern States Power Company - MN	2,910,083	40.59
27	Wisconsin Electric Power Company	2,892,501	40.35
28	Columbus Southern Power Company	2,811,923	39.22
29	Wisconsin Power & Light Company	2,777,078	38.74
30	Ohio Power Company	2,730,742	38.09
31	Indianapolis Power & Light Company	2,684,687	37.45
32	Indiana Michigan Power Company - MI	2,616,909	36.50
33	Public Service Company of Indiana, Inc.	2,517,731	35.12

* Year end rates with average annual fuel cost.

PENNSYLVANIA POWER & LIGHT COMPANY

Comparison of Firm Power Cost for an Industrial Load of 30,000 kW, 74% Load Factor for the Year 1994

Line	Utility	Power Cost* for 1994 (1)	Mills per kWh (2)
1	Philadelphia Electric Company	$14,932,703	76.36
2	Toledo Edison Company, The	13,752,517	70.33
3	Cleveland Electric Illuminating Company, The	11,936,577	61.04
4	Pennsylvania Power & Light Company - Proposed	11,887,534	60.79
5	Northern Indiana Public Service Company	11,881,689	60.76
6	Ohio Edison Company	11,725,898	59.96
7	Detroit Edison Company, The	11,380,243	58.20
8	Pennsylvania Power & Light Company - Present	10,715,936	54.80
9	Commonwealth Edison Company	10,176,269	52.04
10	Consumers Power Company	10,017,240	51.23
11	Duquesne Light Company	10,013,071	51.20
12	Pennsylvania Power Company	9,999,661	51.14
13	Illinois Power Company	9,726,586	49.74
14	Minnesota Power & Light Company	9,625,310	49.22
15	Metropolitan Edison Company	9,432,044	48.23
16	Central Illinois Public Service Company	9,253,679	47.32
17	Pennsylvania Electric Company	9,084,751	46.46
18	Dayton Power and Light Company, The	8,951,503	45.78
19	Cincinnati Gas & Electric Company, The	8,739,217	44.69
20	Northern States Power Company - WI	8,505,633	43.50
21	Central Illinois Light Company	8,159,916	41.73
22	Indiana Michigan Power Company - IN	8,143,904	41.65
23	Wisconsin Public Service Corporation	7,775,527	39.76
24	West Penn Power Company	7,710,958	39.43
25	Northern States Power Company - MN	7,695,594	39.35
26	Union Electric Company - IL	7,403,884	37.86
27	Wisconsin Electric Power Company	7,394,738	37.81
28	Wisconsin Power & Light Company	7,311,505	37.39
29	Columbus Southern Power Company	7,088,741	36.25
30	Indianapolis Power & Light Company	6,898,796	35.28
31	Ohio Power Company	6,706,206	34.29
32	Indiana Michigan Power Company - MI	6,582,079	33.66
33	Public Service Company of Indiana, Inc.	6,364,024	32.54

* Year end rates with average annual fuel cost.

PENNSYLVANIA POWER & LIGHT COMPANY

Comparison of Firm Power Cost for an Industrial Load of 75,000 kW, 74% Load Factor for the Year 1994

Line	Utility	Power Cost* for 1994 (1)	Mills per kWh (2)
1	Philadelphia Electric Company	$35,980,770	74.72
2	Toledo Edison Company, The	34,348,763	71.33
3	Ohio Edison Company	29,486,210	61.23
4	Cleveland Electric Illuminating Company, The	29,390,684	61.03
5	Pennsylvania Power & Light Company - Proposed	29,371,210	60.99
6	Northern Indiana Public Service Company	29,234,458	60.71
7	Detroit Edison Company, The	28,240,263	58.64
8	Pennsylvania Power & Light Company - Present	26,089,898	54.18
9	Duquesne Light Company	25,833,932	53.65
10	Pennsylvania Power Company	24,777,166	51.45
11	Consumers Power Company	24,715,527	51.32
12	Minnesota Power & Light Company	24,532,024	50.94
13	Illinois Power Company	24,016,195	49.87
14	Commonwealth Edison Company	23,621,128	49.05
15	Metropolitan Edison Company	23,492,900	48.79
16	Pennsylvania Electric Company	22,452,989	46.63
17	Central Illinois Public Service Company	22,342,908	46.40
18	Dayton Power and Light Company, The	22,157,671	46.01
19	Northern States Power Company - WI	20,981,740	43.57
20	Cincinnati Gas & Electric Company, The	20,976,852	43.56
21	Indiana Michigan Power Company - IN	20,830,379	43.26
22	Central Illinois Light Company	20,340,378	42.24
23	Wisconsin Public Service Corporation	19,217,150	39.91
24	West Penn Power Company	19,148,899	39.76
25	Northern States Power Company - MN	18,971,667	39.40
26	Wisconsin Electric Power Company	18,395,397	38.20
27	Union Electric Company - IL	18,193,378	37.78
28	Wisconsin Power & Light Company	18,131,604	37.65
29	Columbus Southern Power Company	17,455,126	36.25
30	Indianapolis Power & Light Company	17,121,711	35.55
31	Ohio Power Company	16,550,736	34.37
32	Indiana Michigan Power Company - MI	16,369,223	33.99
33	Public Service Company of Indiana, Inc.	16,076,303	33.38

* Year end rates with average annual fuel cost.

PENNSYLVANIA POWER & LIGHT COMPANY

PP&L's Ranking in the Annual Midwest Industrial Rate Comparison of 32 Electric Utilities 1981 - 1994

Year	75,000 kW 74% Load Factor (1)	30,000 kW 74% Load Factor (2)	12,000 kW 68% Load Factor (3)
1981	26	25	N/A
1982	N/A	N/A	N/A
1983	7	6	N/A
1984	18	18	N/A
1985	14	12	N/A
1986	11	9	10
1987	8	7	7
1988	6	6	7
1989	10	9	9
1990	9	8	10
1991	9	10	10
1992	8	8	9
1993	8	7	8
1994	7	7	8

PENNSYLVANIA POWER & LIGHT COMPANY

Comparison of Interruptible Power Costs for an Industrial Load of 12,000 kW, 68% Load Factor for the Year 1994

Line	Utility	Power Costs* for 1994 (1)	Mills per kWh (2)
1	Duquesne Light Company	4,242,388	59.18
2	Ohio Edison Company	4,175,667	58.25
3	Detroit Edison Company, The	4,014,970	56.00
4	Northern Indiana Public Service Company	3,945,855	55.04
5	Pennsylvania Power & Light Company - Proposed	3,641,535	50.79
6	Toledo Edison Company, The	3,587,174	50.04
7	Pennsylvania Power Company	3,472,611	48.44
8	Consumers Power Company	3,253,851	45.39
9	Commonwealth Edison Company	3,230,356	45.06
10	Metropolitan Edison Company	3,163,786	44.13
11	Dayton Power and Light Company, The	3,105,515	43.32
12	Cleveland Electric Illuminating Company, The	2,859,701	39.89
13	Northern States Power Company - WI	2,858,223	39.87
14	Illinois Power Company	2,833,947	39.53
15	Pennsylvania Electric Company	2,811,947	39.22
16	Pennsylvania Power & Light Company - Present	2,781,165	38.79
17	Cincinnati Gas & Electric Company, The	2,722,267	37.97
18	Indiana Michigan Power Company - IN	2,702,394	37.69
19	Philadelphia Electric Company	2,669,637	37.24
20	West Penn Power Company	2,619,832	36.54
21	Columbus Southern Power Company	2,618,931	36.53
22	Indianapolis Power & Light Company	2,453,449	34.22
23	Indiana Michigan Power Company - MI	2,316,724	32.32
24	Ohio Power Company	2,289,092	31.93
25	Northern States Power Company - MN	2,263,163	31.57
26	Wisconsin Public Service Corporation	2,252,967	31.43
27	Union Electric Company - IL	2,237,017	31.20
28	Wisconsin Power & Light Company	2,226,392	31.06
29	Wisconsin Electric Power Company	2,195,257	30.62
30	Minnesota Power & Light Company	N/A	
31	Public Service Company of Indiana, Inc.	Negotiable	
32	Central Illinois Public Service Company	Negotiable	
33	Central Illinois Light Company	Negotiable	

*Year end rates with average annual fuel cost.

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Present Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
1	Operating Revenues @ Present Rate Levels												
2	Sale of Electricity												
3	Rate Revenue	2,263,602	909,213	20,360	165,977	520,355	281,626	268,654	8,665	21,238	44,746	21,591	1,177
4	Energy/Fuel Cost Revenue	(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)	(4,364)	(116)	(422)	(375)	(72)	(9)
5	EDI/IDI Adjustment	0	(12,679)	(247)	(2,433)	(3,850)	9,678	9,979	(111)	642	(622)	(340)	(17)
6	State Tax Adj Surcharge	0	0	0	0	0	0	0	0	0	0	0	0
7	Spec Base Rate Credit Adj	(38,084)	(15,093)	(338)	(2,755)	(8,692)	(4,896)	(4,678)	(144)	(367)	(743)	(358)	(20)
8	Total Sale of Electricity	2,204,031	874,433	19,527	159,784	503,322	283,031	269,591	8,294	21,091	43,006	20,821	1,131
9	Annualization	25,615	8,192	367	3,393	5,340	4,745	4,973	0	0	(1,014)	(381)	0
10	Late Pay Charges	7,074	3,508	27	1,314	1,528	377	133	0	0	135	52	0
11	Total Adj Sale of Electricity	2,236,720	886,133	19,921	164,491	510,190	288,153	274,697	8,294	21,091	42,127	20,492	1,131
12	Other Operating Revenues	165,535	63,805	2,383	8,764	35,788	22,241	25,249	698	2,165	3,132	1,256	56
13	Total Operating Revenues	2,402,255	949,938	22,304	173,255	545,978	310,393	299,946	8,992	23,256	45,259	21,748	1,187
14													
15	Operating Expenses												
16	Operation & Maintenance Expenses												
17	Production												
18	Fuel	431,704	153,338	5,471	21,424	94,561	62,645	75,889	1,973	7,159	7,616	1,475	154
19	Power Purchases	252,511	92,014	3,503	12,703	56,413	35,999	41,518	1,156	3,504	4,810	798	93
20	Other Production	297,079	114,111	4,886	15,377	69,149	40,733	41,611	1,367	2,400	6,553	775	116
21	Total Production	981,294	359,462	13,861	49,504	220,123	139,377	159,019	4,496	13,063	18,979	3,048	362
22	Transmission	10,487	4,026	192	529	2,410	1,366	1,512	46	131	252	20	4
23	Distribution	92,936	51,716	2,092	7,738	15,501	5,467	2,367	83	216	2,145	5,604	6
24	Other Oper & Maint Expense	288,210	160,052	4,640	19,559	47,728	24,935	22,672	807	966	4,927	1,854	71
25	Total Oper & Maint Expenses	1,372,927	575,255	20,784	77,331	285,762	171,145	185,570	5,432	14,376	26,303	10,525	443
26													
27	Depreciation Expense												
28	Production	231,599	94,116	4,483	12,369	56,355	30,329	26,069	1,071	355	5,897	460	97
29	Transmission	7,753	2,988	142	393	1,789	1,013	1,122	26	75	187	15	3
30	Distribution	70,147	41,443	1,513	5,654	10,579	3,279	1,415	47	126	1,409	4,680	4
31	Other Deprec Expense	11,298	5,761	211	735	2,179	1,089	891	36	19	240	134	3
32	Total Depreciation Expense	320,797	144,307	6,349	19,150	70,901	35,710	29,497	1,179	575	7,733	5,289	107
33	Amoritzation Expense (Acct 406)	0	0	0	0	0	0	0	0	0	0	0	0
34	Total Depreciation & Amort Expense	320,797	144,307	6,349	19,150	70,901	35,710	29,497	1,179	575	7,733	5,289	107
35													
36	Misc Allowable Expenses	(29,674)	(12,035)	(571)	(1,583)	(7,209)	(3,893)	(3,370)	(137)	(52)	(752)	(60)	(12)
37													
38	Taxes												
39	-Other Capital Stock	30,553	14,049	614	1,860	6,676	3,299	2,656	104	62	734	490	9
40	-Other w/o Cap Stock	57,585	27,150	1,106	3,563	12,039	6,072	5,116	191	171	1,304	856	17
41	Deferred Income Taxes	(15,424)	(3,826)	(248)	(496)	(4,751)	(3,051)	(3,045)	(123)	(57)	(431)	613	(11)
42	Net Inv Tax Cr	(8,625)	(3,999)	(173)	(529)	(1,862)	(915)	(734)	(29)	(18)	(205)	(159)	(3)
43	Gross Receipts Tax	98,416	38,990	877	7,238	22,448	12,679	12,087	365	928	1,854	902	50
44	PA & Fed Income Taxes	209,079	51,567	(3,516)	25,438	62,708	36,067	30,173	832	3,097	2,904	(436)	245
45	Total Taxes	371,583	123,931	(1,340)	37,073	97,258	54,151	46,253	1,340	4,184	6,159	2,266	308
46													
47	Operating Expenses	2,035,633	831,459	25,222	131,970	446,713	257,114	257,951	7,815	19,082	39,443	18,020	845
48													
49	Return	366,622	118,480	(2,918)	41,285	99,264	53,279	41,995	1,178	4,174	5,815	3,728	342
50													
51	Total Rate Base	5,017,177	2,320,930	100,619	307,276	1,085,876	535,407	432,997	16,618	11,725	119,457	84,764	1,507
52													
53	Rate of Return	7.31%	5.10%	-2.90%	13.44%	9.14%	9.95%	9.70%	7.09%	35.60%	4.87%	4.40%	22.67%
54													
55	Index	100.0	69.9	-39.7	183.9	125.1	136.2	132.7	97.0	487.2	66.6	60.2	310.2

Exhibit MEB-3 ( )
Schedule 1
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PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Present Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
1	Rate Base												
2													
3	Plant in Service												
4	Production	5,021,440	2,040,586	97,189	268,177	1,221,857	657,576	565,215	23,216	7,687	127,859	9,982	2,096
5	Transmission	365,607	140,881	6,710	18,515	84,356	47,792	52,914	1,241	3,537	8,827	689	145
6	Distribution	2,532,998	1,477,443	55,187	198,276	409,887	137,807	57,781	1,840	5,081	52,466	137,080	151
7	Other	276,661	141,072	5,171	17,988	53,360	26,665	21,830	873	468	5,873	3,282	79
8	Common Plant (Acct 186)	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Plant in Service	8,196,706	3,799,982	164,257	502,956	1,769,460	869,839	697,740	27,170	16,773	195,025	151,033	2,471
10													
11	Depreciation Reserve												
12	Production	1,396,759	567,608	27,034	74,596	339,871	182,911	157,220	6,458	2,138	35,565	2,777	583
13	Transmission	116,155	44,759	2,132	5,882	26,800	15,184	16,811	394	1,124	2,804	219	46
14	Distribution	867,290	508,263	18,327	68,041	134,377	44,785	18,847	597	1,655	17,201	55,147	49
15	General Plant	89,267	45,518	1,668	5,804	17,217	8,604	7,043	282	151	1,895	1,059	25
16	Intangible Plant	7,651	3,901	143	497	1,476	737	604	24	13	162	91	2
17	Total Depreciation Reserve	2,477,122	1,170,048	49,305	154,820	519,741	252,220	200,525	7,755	5,081	57,628	59,292	706
18	Amortization Res (Acct 186)	0	0	0	0	0	0	0	0	0	0	0	0
19	Total Depreciation & Amortization Reserve	2,477,122	1,170,048	49,305	154,820	519,741	252,220	200,525	7,755	5,081	57,628	59,292	706
20													
21	Total Net Plant in Service	5,719,584	2,629,934	114,952	348,136	1,249,719	617,619	497,215	19,414	11,693	137,397	91,741	1,765
22													
23	Total Subtractive Adjustment	903,062	389,548	17,694	51,712	208,810	108,126	90,740	3,636	1,685	22,283	8,500	329
24													
25	Total Additive Adjustments	12,378	4,752	226	624	2,845	1,612	1,785	54	154	298	23	5
26													
27	Total Net Orig Cost Rate Base	4,828,900	2,245,137	97,485	297,048	1,043,754	511,105	408,260	15,832	10,162	115,412	83,265	1,441
28													
29	Working Capital												
30	Fuel Inventory												
31	Wholly-Owned Coal	62,590	22,232	793	3,106	13,710	9,082	11,003	286	1,038	1,104	214	22
32	Other Non-Nuclear	26,124	9,279	331	1,296	5,722	3,791	4,592	119	433	461	89	9
33	Nuclear Fuel	0	0	0	0	0	0	0	0	0	0	0	0
34	Total Fuel	88,714	31,511	1,124	4,403	19,432	12,873	15,595	405	1,471	1,565	303	32
35	Other	99,563	44,283	2,010	5,826	22,690	11,429	9,142	380	93	2,480	1,196	35
36	Total Working Capital	188,277	75,793	3,134	10,228	42,122	24,302	24,737	786	1,564	4,045	1,499	66
37													
38	Total Rate Base	5,017,177	2,320,930	100,619	307,276	1,085,876	535,407	432,997	16,618	11,725	119,457	84,764	1,507

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Present Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
	Allocators												
1	Customers (Weighted)												
2	Meter Investment	82,998	39,573	3,057	13,650	16,002	3,609	2,594	168	316	4,029	0	0
3	Meter Reading Expense	9,373	7,860	127	968	229	86	19	1	0	83	0	0
4	Late Payments	6,763	3,354	26	1,256	1,461	360	127	0	0	129	50	0
5	Uncollectible Accounts	10,628	8,659	76	742	863	213	75	0	0	0	0	0
6	Customer Deposits	1,065	20	0	298	654	45	3	0	0	45	0	0
7	Customer Advances	39.911	15.512	0.000	17.168	7.231	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Line Transformers, Cust Comp	1,475,214	1,080,235	14,671	165,519	49,196	0	0	0	0	8,274	157,319	0
9	Services Customer Component	1,413,615	1,074,207	14,614	134,564	27,373	0	0	0	0	5,538	157,319	0
10													
11	Customers (Units)												
12	Total Customers	1,228,047	1,066,688	14,544	121,411	18,948	843	119	1	1	4,473	1,010	9
13	FERC System Customers	0	0	0	0	0	0	0	0	0	0	0	0
14	Secondary Customers	1,227,074	1,066,688	14,544	121,411	18,948	0	0	0	0	4,473	1,010	0
15													
16	Demands (kW)												
17	Generation Level Demands	5,325,423	2,044,279	97,365	268,662	1,224,068	693,487	767,820	23,258	66,294	128,090	10,000	2,100
18	69 KV Level Demands	5,235,871	2,044,279	97,365	268,662	1,224,068	693,487	767,820	0	0	128,090	10,000	2,100
19	Primary Level Demands	4,465,951	2,044,279	97,365	268,662	1,224,068	693,487	0	0	0	128,090	10,000	0
20	Class Maximum Demand FTY	5,971,000	3,396,000	265,000	465,000	1,590,000	0	0	0	0	228,000	27,000	0
21													
22	Energy (MWh)												
23	Generation Level Energy	33,464,555	11,886,363	424,093	1,660,724	7,330,148	4,856,058	5,882,751	152,923	554,938	590,334	114,314	11,909
24	Sales Level MWh Sales	31,406,086	11,001,081	392,507	1,537,035	6,784,205	4,608,804	5,729,073	148,928	540,441	546,615	105,799	11,598
25													
26	Direct Assignment												
27	Area Lights	1	0	0	0	0	0	0	0	0	0	1	0
28	Street Lights	1	0	0	0	0	0	0	0	0	0	1	0
29													
30													
31	Rate Revenue Present Level	2,263,602	909,213	20,360	165,977	520,355	281,626	268,654	8,665	21,238	44,746	21,591	1,177
32	Energy Revenue Present Level	(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)	(4,364)	(116)	(422)	(375)	(72)	(9)
33	State Tax Adj Surcharge	0	0	0	0	0	0	0	0	0	0	0	0
34	Spec Base Rate Credit Adj	(38,084)	(15,093)	(338)	(2,755)	(8,692)	(4,896)	(4,678)	(144)	(367)	(743)	(358)	(20)
35	Annualization Revenues	25,615	8,192	367	3,393	5,340	4,745	4,973	0	0	(1,014)	(381)	0
36	Annualization	28,529	9,122	409	3,779	5,948	5,285	5,539	0	0	(1,129)	(424)	0

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Present Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
	Adjustments to Cost of Service Study												
1	1) *EDI & IDI Credits:*												
2	Economic Development Initiative Credit	(27,230)	0	0	0	(1,964)	(12,061)	(12,333)	0	(872)	0	0	0
3	Industial Development Initiative Credit	(3,394)	0	0	0	(1,315)	(1,258)	(821)	0	0	0	0	0
4	Total Credits	(30,624)	0	0	0	(3,279)	(13,319)	(13,154)	0	(872)	0	0	0
5													
6	Allocation of Credits:												
7	Sales of Electricity	2,204,031	887,112	19,774	162,217	507,172	273,353	259,612	8,405	20,449	43,628	21,161	1,148
8	Less: Fuel Expense	431,704	153,338	5,471	21,424	94,561	62,645	75,889	1,973	7,159	7,616	1,475	154
9	Allocation Factor	1,772,327	733,774	14,303	140,793	412,611	210,708	183,723	6,432	13,290	36,012	19,686	994
10	Allocated Credits	(30,624)	(12,679)	(247)	(2,433)	(7,129)	(3,641)	(3,175)	(111)	(230)	(622)	(340)	(17)
11													
12	EDI & IDI Adjustment	0	(12,679)	(247)	(2,433)	(3,850)	9,678	9,979	(111)	642	(622)	(340)	(17)
13													
14	2) NUG Allocator:												
15	Energy (191,629 / 229,157)	83.6%											
16	Demand	16.4%											
17	Total	100.0%											
18													
19	3) Remove Interruptible Levels from												
20	Allocation of Production Demand Costs;												
21	and Eliminate "Rate Base" Credit												
22													
23	Demands to Total Customers (MW)												
24	Generation Level Demands	5,325,423	2,044,279	97,365	268,662	1,224,068	693,487	767,820	23,258	66,294	128,090	10,000	2,100
25	Demands to Interruptible Customers (MW)												
26	Generation Level Demands *	294,896	0	0	0	0	34,721	201,582	0	58,593	0	0	0
27	Demands to Firm Customers (MW)												
28	Generation Level Demands	5,030,527	2,044,279	97,365	268,662	1,224,068	658,766	566,238	23,258	7,701	128,090	10,000	2,100
29													
30	Adjustment to ISA Firm Demands												
31	*7,500 kW is Firm*									7,500			
32	x Losses (using energy losses)									1.0268			
33	= Firm Amount of ISA									7,701			
34													
35	* LP-4 & LP-5 from OCA Set III, Q20												
36	ISA is difference between Total and Firm												

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Proposed Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
1	Operating Revenues @ Proposed Rate Levels												
2	Sale of Electricity												
3	Rate Revenue	2,525,900	1,047,123	23,856	172,388	555,030	309,896	309,443	9,136	21,270	51,906	24,667	1,185
4	Energy/Fuel Cost Revenue	(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)	(4,364)	(116)	(422)	(375)	(72)	(9)
5	EDI/IDI Adjustment	0	(13,582)	(277)	(2,298)	(3,700)	10,547	9,796	(108)	664	(673)	(355)	(16)
6	State Tax Adj Surcharge	0	0	0	0	0	0	0	0	0	0	0	0
7	Spec Base Rate Credit Adj	(42,456)	(17,382)	(396)	(2,862)	(9,268)	(5,381)	(5,357)	(152)	(368)	(862)	(408)	(20)
8	Total Sale of Electricity	2,461,957	1,009,151	22,935	166,223	537,571	311,685	309,518	8,760	21,144	49,996	23,832	1,140
9	Annualization	28,529	9,122	409	3,779	5,948	5,285	5,539	0	0	(1,129)	(424)	0
10	Late Pay Charges	7,869	3,903	30	1,461	1,700	419	148	0	0	150	58	0
11	Total Adj Sale of Electricity	2,498,355	1,022,176	23,374	171,463	545,219	317,389	315,205	8,760	21,144	49,018	23,466	1,140
12	Other Operating Revenues	165,535	63,805	2,383	8,764	35,788	22,241	25,249	698	2,165	3,132	1,256	56
13	Total Operating Revenues	2,663,890	1,085,980	25,757	180,227	581,007	339,630	340,454	9,459	23,308	52,149	24,722	1,196
14													
15	Operating Expenses												
16	Operation & Maintenance Expenses												
17	Production												
18	Fuel	431,704	153,338	5,471	21,424	94,561	62,645	75,889	1,973	7,159	7,616	1,475	154
19	Power Purchases	252,511	92,014	3,503	12,703	56,413	35,999	41,518	1,156	3,504	4,810	798	93
20	Other Production	297,079	114,111	4,886	15,377	69,149	40,733	41,611	1,367	2,400	6,553	775	116
21	Total Production	981,294	359,462	13,861	49,504	220,123	139,377	159,019	4,496	13,063	18,979	3,048	362
22	Transmission	10,487	4,026	192	529	2,410	1,366	1,512	46	131	252	20	4
23	Distribution	92,936	51,716	2,092	7,738	15,501	5,467	2,367	83	216	2,145	5,604	6
24	Other Oper & Maint Expense	288,210	160,052	4,640	19,559	47,728	24,935	22,672	807	966	4,927	1,854	71
25	Total Oper & Maint Expenses	1,372,927	575,255	20,784	77,331	285,762	171,145	185,570	5,432	14,376	26,303	10,525	443
26													
27	Depreciation Expense												
28	Production	231,599	94,116	4,483	12,369	56,355	30,329	26,069	1,071	355	5,897	460	97
29	Transmission	7,753	2,988	142	393	1,789	1,013	1,122	26	75	187	15	3
30	Distribution	70,147	41,443	1,513	5,654	10,579	3,279	1,415	47	126	1,409	4,680	4
31	Other Deprec Expense	11,298	5,761	211	735	2,179	1,089	891	36	19	240	134	3
32	Total Depreciation Expense	320,797	144,307	6,349	19,150	70,901	35,710	29,497	1,179	575	7,733	5,289	107
33	Amortization Expense (Acct 406)	0	0	0	0	0	0	0	0	0	0	0	0
34	Total Depreciation & Amort Expense	320,797	144,307	6,349	19,150	70,901	35,710	29,497	1,179	575	7,733	5,289	107
35													
36	Misc Allowable Expenses	(29,674)	(12,035)	(571)	(1,583)	(7,209)	(3,893)	(3,370)	(137)	(52)	(752)	(60)	(12)
37													
38	Taxes												
39	-Other Capital Stock	32,385	14,891	651	1,971	7,076	3,497	2,815	110	66	778	519	10
40	-Other w/o Cap Stock	57,585	27,150	1,106	3,563	12,039	6,072	5,116	191	171	1,304	856	17
41	Deferred Income Taxes	(15,424)	(3,826)	(248)	(496)	(4,751)	(3,051)	(3,045)	(123)	(57)	(431)	613	(11)
42	Net Inv Tax Cr	(8,625)	(3,999)	(173)	(529)	(1,862)	(915)	(734)	(29)	(18)	(205)	(159)	(3)
43	Gross Receipts Tax	109,928	44,976	1,028	7,544	23,990	13,965	13,869	385	930	2,157	1,033	50
44	PA & Fed Income Taxes	313,717	106,022	(2,141)	28,201	76,652	47,763	46,426	1,017	3,116	5,662	750	249
45	Total Taxes	489,566	185,214	225	40,253	113,144	67,331	64,447	1,552	4,209	9,264	3,613	313
46													
47	Operating Expenses	2,153,616	892,742	26,786	135,151	462,599	270,294	276,145	8,027	19,107	42,548	19,367	850
48													
49	Return	510,274	193,238	(1,029)	45,077	118,408	69,336	64,308	1,432	4,201	9,601	5,356	347
50													
51	Total Rate Base	5,017,177	2,320,930	100,619	307,276	1,085,876	535,407	432,997	16,618	11,725	119,457	84,764	1,507
52													
53	Rate of Return	10.17%	8.33%	-1.02%	14.67%	10.90%	12.95%	14.85%	8.62%	35.83%	8.04%	6.32%	22.99%
54													
55	Index	100.0	81.9	-10.1	144.2	107.2	127.3	146.0	84.7	352.3	79.0	62.1	226.1

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Proposed Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
1	Rate Base												
2													
3	Plant in Service												
4	Production	5,021,440	2,040,586	97,189	268,177	1,221,857	657,576	565,215	23,216	7,687	127,859	9,982	2,096
5	Transmission	365,607	140,881	6,710	18,515	84,356	47,792	52,914	1,241	3,537	8,827	689	145
6	Distribution	2,532,998	1,477,443	55,187	198,276	409,887	137,807	57,781	1,840	5,081	52,466	137,080	151
7	Other	276,661	141,072	5,171	17,988	53,360	26,665	21,830	873	468	5,873	3,282	79
8	Common Plant (Acct 186)	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Plant in Service	8,196,706	3,799,982	164,257	502,956	1,769,460	869,839	697,740	27,170	16,773	195,025	151,033	2,471
10													
11	Depreciation Reserve												
12	Production	1,396,759	567,608	27,034	74,596	339,871	182,911	157,220	6,458	2,138	35,565	2,777	583
13	Transmission	116,155	44,759	2,132	5,882	26,800	15,184	16,811	394	1,124	2,804	219	46
14	Distribution	867,290	508,263	18,327	68,041	134,377	44,785	18,847	597	1,655	17,201	55,147	49
15	General Plant	89,267	45,518	1,668	5,804	17,217	8,604	7,043	282	151	1,895	1,059	25
16	Intangible Plant	7,651	3,901	143	497	1,476	737	604	24	13	162	91	2
17	Total Depreciation Reserve	2,477,122	1,170,048	49,305	154,820	519,741	252,220	200,525	7,755	5,081	57,628	59,292	706
18	Amortization Res (Acct 186)	0	0	0	0	0	0	0	0	0	0	0	0
19	Total Depreciation & Amortization Reserve	2,477,122	1,170,048	49,305	154,820	519,741	252,220	200,525	7,755	5,081	57,628	59,292	706
20													
21	Total Net Plant in Service	5,719,584	2,629,934	114,952	348,136	1,249,719	617,619	497,215	19,414	11,693	137,397	91,741	1,765
22													
23	Total Subtractive Adjustment	903,062	389,548	17,694	51,712	208,810	108,126	90,740	3,636	1,685	22,283	8,500	329
24													
25	Total Additive Adjustments	12,378	4,752	226	624	2,845	1,612	1,785	54	154	298	23	5
26													
27	Total Net Orig Cost Rate Base	4,828,900	2,245,137	97,485	297,048	1,043,754	511,105	408,260	15,832	10,162	115,412	83,265	1,441
28													
29	Working Capital												
30	Fuel Inventory												
31	Wholly-Owned Coal	62,590	22,232	793	3,106	13,710	9,082	11,003	286	1,038	1,104	214	22
32	Other Non-Nuclear	26,124	9,279	331	1,296	5,722	3,791	4,592	119	433	461	89	9
33	Nuclear Fuel	0	0	0	0	0	0	0	0	0	0	0	0
34	Total Fuel	88,714	31,511	1,124	4,403	19,432	12,873	15,595	405	1,471	1,565	303	32
35	Other	99,563	44,283	2,010	5,826	22,690	11,429	9,142	380	93	2,480	1,196	35
36	Total Working Capital	188,277	75,793	3,134	10,228	42,122	24,302	24,737	786	1,564	4,045	1,499	66
37													
38	Total Rate Base	5,017,177	2,320,930	100,619	307,276	1,085,876	535,407	432,997	16,618	11,725	119,457	84,764	1,507

PENNSYLVANIA POWER & LIGHT COMPANY

PPUC JURISDICTIONAL COST ALLOCATION

12 CP Method @ Proposed Rate Levels (w/Adjustments)

Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
	Allocators												
1	Customers (Weighted)												
2	Meter Investment	82,998	39,573	3,057	13,650	16,002	3,609	2,594	168	316	4,029	0	0
3	Meter Reading Expense	9,373	7,860	127	968	229	86	19	1	0	83	0	0
4	Late Payments	6,763	3,354	26	1,256	1,461	360	127	0	0	129	50	0
5	Uncollectible Accounts	10,628	8,659	76	742	863	213	75	0	0	0	0	0
6	Customer Deposits	1,065	20	0	298	654	45	3	0	0	45	0	0
7	Customer Advances	39.911	15.512	0.000	17.168	7.231	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Line Transformers, Cust Comp	1,475,214	1,080,235	14,671	165,519	49,196	0	0	0	0	8,274	157,319	0
9	Services Customer Component	1,413,615	1,074,207	14,614	134,564	27,373	0	0	0	0	5,538	157,319	0
10													
11	Customers (Units)												
12	Total Customers	1,228,047	1,066,688	14,544	121,411	18,948	843	119	1	1	4,473	1,010	9
13	FERC System Customers	0	0	0	0	0	0	0	0	0	0	0	0
14	Secondary Customers	1,227,074	1,066,688	14,544	121,411	18,948	0	0	0	0	4,473	1,010	0
15													
16	Demands (kW)												
17	Generation Level Demands	5,325,423	2,044,279	97,365	268,662	1,224,068	693,487	767,820	23,258	66,294	128,090	10,000	2,100
18	69 KV Level Demands	5,235,871	2,044,279	97,365	268,662	1,224,068	693,487	767,820	0	0	128,090	10,000	2,100
19	Primary Level Demands	4,465,951	2,044,279	97,365	268,662	1,224,068	693,487	0	0	0	128,090	10,000	0
20	Class Maximum Demand FTY	5,971,000	3,396,000	265,000	465,000	1,590,000	0	0	0	0	228,000	27,000	0
21													
22	Energy (MWh)												
23	Generation Level Energy	33,464,555	11,886,363	424,093	1,660,724	7,330,148	4,856,058	5,882,751	152,923	554,938	590,334	114,314	11,909
24	Sales Level MWh Sales	31,406,086	11,001,081	392,507	1,537,035	6,784,205	4,608,804	5,729,073	148,928	540,441	546,615	105,799	11,598
25													
26	Direct Assignment												
27	Area Lights	1	0	0	0	0	0	0	0	0	0	1	0
28	Street Lights	1	0	0	0	0	0	0	0	0	0	1	0
29													
30													
31	Rate Revenue Proposed Level	2,525,900	1,047,123	23,856	172,388	555,030	309,896	309,443	9,136	21,270	51,906	24,667	1,185
32	Energy Revenue Proposed Level	(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)	(4,364)	(116)	(422)	(375)	(72)	(9)
33	State Tax Adj Surcharge	0	0	0	0	0	0	0	0	0	0	0	0
34	Spec Base Rate Credit Adj	(42,456)	(17,382)	(396)	(2,862)	(9,268)	(5,381)	(5,357)	(152)	(368)	(862)	(408)	(20)
35	Annualization Revenues	25,615	8,192	367	3,393	5,340	4,745	4,973	0	0	(1,014)	(381)	0
36	Annualization	28,529	9,122	409	3,779	5,948	5,285	5,539	0	0	(1,129)	(424)	0

PENNSYLVANIA POWER & LIGHT COMPANY
PPUC JURISDICTIONAL COST ALLOCATION
12 CP Method @ Proposed Rate Levels (w/Adjustments)
Future Test Year Ended 9/30/95

Line	Description	Total PA Juris (1)	RS (2)	RTS (3)	GS-1 (4)	GS-3 (5)	LP-4 (6)	LP-5 (7)	LPEP (8)	ISA (9)	GH (10)	SL/AL (11)	Standby (12)
	Adjustments to Cost of Service Study												
1	1) EDI & IDI Credits:												
2	Economic Development Initiative Credit	(28,323)	0	0	0	(1,964)	(13,015)	(12,472)	0	(872)	0	0	0
3	Industial Development Initiative Credit	(3,394)	0	0	0	(1,315)	(1,258)	(821)	0	0	0	0	0
4	Total Credits	(31,717)	0	0	0	(3,279)	(14,273)	(13,293)	0	(872)	0	0	0
5													
6	Allocation of Credits:												
7	Sales of Electricity	2,461,957	1,022,733	23,212	168,521	541,271	301,138	299,722	8,868	20,480	50,669	24,187	1,156
8	Less: Fuel Expense	431,704	153,338	5,471	21,424	94,561	62,645	75,889	1,973	7,159	7,616	1,475	154
9	Allocation Factor	2,030,253	869,395	17,741	147,097	446,710	238,493	223,833	6,895	13,321	43,053	22,712	1,002
10	Allocated Credits	(31,717)	(13,582)	(277)	(2,298)	(6,979)	(3,726)	(3,497)	(108)	(208)	(673)	(355)	(16)
11													
12	EDI & IDI Adjustment	0	(13,582)	(277)	(2,298)	(3,700)	10,547	9,796	(108)	664	(673)	(355)	(16)
13													
14	2) NUG Allocator:												
15	Energy (191,629 / 229,157)	83.6%											
16	Demand	16.4%											
17	Total	100.0%											
18													
19	3) Remove Interruptible Levels from												
20	Allocation of Production Demand Costs;												
21	and Eliminate "Rate Base" Credit												
22													
23	Demands to Total Customers (MW)												
24	Generation Level Demands	5,325,423	2,044,279	97,365	268,662	1,224,068	693,487	767,820	23,258	66,294	128,090	10,000	2,100
25	Demands to Interruptible Customers (MW)												
26	Generation Level Demands *	294,896	0	0	0	0	34,721	201,582	0	58,593	0	0	0
27	Demands to Firm Customers (MW)												
28	Generation Level Demands	5,030,527	2,044,279	97,365	268,662	1,224,068	658,766	566,238	23,258	7,701	128,090	10,000	2,100
29													
30	Adjustment to ISA Firm Demands												
31	7,500 kW is Firm									7,500			
32	x Losses (using energy losses)									1.0268			
33	= Firm Amount of ISA									7,701			
34													
35	* LP-4 & LP-5 from OCA Set III, Q20												
36	ISA is difference between Total and Firm												

CEPFOD Statement No. 1

SM
4-26-95
Hhg
R-943271

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Regarding

PENNSYLVANIA POWER & LIGHT COMPANY
Docket Number R-00943271

DOCKETED
APR 2? 1995

DOCUMENT FOLDER

Direct Testimony Of
Steven Andersen

On Behalf of
Central Eastern Pennsylvania Fuel Oil Dealers

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INFO. CONTROL DIV.

Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, Texas 78727

April 12, 1995

TABLE OF CONTENTS

Schedule

Appendix

Exhibits

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven Andersen. My business address is 13300 Council Bluff Drive, Austin, Texas 78727.

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

A. I am the principal of Economic & Policy Analysis, Inc. (EPA), a consulting firm specializing in regulatory analysis and asset valuation. I am testifying on behalf of the the Central Eastern Pennsylvania Fuel Oil Dealers (CEPFOD).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a bachelor's degree in Economics from the City College of New York in 1968, and a Ph.D. in Economics from Rutgers University in 1972. During the 1971-1972 academic year, I was a research fellow at the Brookings Institution in Washington, D.C. Between 1972 and 1979, I taught theoretical and applied economics at Rutgers University and at the Oswego campus of the State University of New York. From June 1979 to March 1989 I was employed as a regulatory economist by state agencies in Missouri and Texas. In 1989 I established EPA. My academic and applied experience in the area of regulatory economics spans a total of more than twenty years.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Arizona Corporation Commission, the Federal Energy Regulatory Commission, the Illinois Commerce Commission, the Iowa Utilities Board, the Kansas Corporation Commission, the Missouri Public Service Commission, the Public Utility Regulatory Board of the City of El Paso, the Texas Public Utility Commission, and the Texas Water Commission. Since 1979, I have provided testimony in over 75 proceedings pertaining to revenue requirement, cost allocation, and rate design issues for electric, natural gas, water, and telephone utilities. I have also published several articles in economic journals and presented papers or served as a panelist at professional association meetings and conferences.

Q. HAVE YOU PREPARED A MORE DETAILED SUMMARY OF YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE?

A. Yes. A detailed summary is attached as an appendix to this testimony.

II. Scope and Summary

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A. I have been retained by the CEPFOD to evaluate the class cost of service study and the retail rates proposed by Pennsylvania Power & Light Company (PP&L or Company).

Q. WHAT IS CEPFOD'S INTEREST IN THESE ISSUES?

A. The membership of CEPFOD is served by PP&L, and therefore has a direct interest in the Company's rates for residential and commercial service. The membership of CEPFOD is also in direct competition with PP&L in certain segments of the energy market. From this perspective, the membership is concerned that certain services offered by PP&L may be priced below cost, and subsidized by revenues from other services. If PP&L services that are in competition with fuel oil are subsidized, both CEPFOD's members and other rate classes are harmed.

Q. WHAT SPECIFIC RATES HAVE YOU EVALUATED?

A. My testimony focuses on PP&L's rate for residential thermal storage (RTS) service and the structure of the Company's rate for standard residential (RS) service.

Q. TO WHAT TYPES OF SERVICE DOES THE RTS RATE APPLY?

A. The RTS rate is available to electric space heating customers that install water, ceramic, or other solid forms of heat storage capacity. The primary storage technologies for which RTS service is available are:

Heat Pump Plus, which uses water that is heated and stored at night to replace resistance units as a supplemental heat source during the day;

Ceramic storage, which provides heat throughout the day from energy stored in ceramic bricks heated at night; and

Hydronic storage, which uses a central water tank or a solid medium to store heat that is transferred to the heating loop during the day.

RTS service is available for both new construction, and for customers converting from conventional to storage based electric heating systems.

Q. HAS PP&L ACTIVELY PROMOTED THE RTS RATE?

A. Yes. PP&L has paid incentives of $250 to $1250 to customer that install storage heating systems, provided grants when electric service upgrades were required to accommodate storage, offered discount financing for conversions, and offered marketing incentives to contractors and employees. In addition, the net effective cost of operating a qualifying system is subsidized. Under the RTS rate, a customer pays only about $.02 per kWh for heating service. This is not even sufficient to recover off-peak fuel expense (CEPFOD 7), and is 68 percent below the current tail block rate ($.0636 per kWh) for RS service.

Q. HAVE YOU ANALYZED THE RTS RATE AS A DEMAND SIDE MANAGEMENT (DSM) TOOL?

A. Yes.

Q. HAVE YOU ALSO ANALYZED THE CLASS COST OF SERVICE STUDY AND RATE DESIGN FILED BY PP&L?

A. Yes.

Q. DO THE RESULTS OF YOUR ANALYSIS SUPPORT CEPFOD'S CONCERNS REGARDING SUBSIDIES?

A. Yes. RTS service is not a cost-effective DSM program. In addition, the class cost of service study sponsored by Mr. Kleha indicates that the rate for RTS service is substantially below the embedded cost of providing service. Even after the 17 percent increase proposed by PP&L, revenues from this service will recover only about 55 percent of cost. Based on my analysis of RS class load characteristics, I also conclude that the discount that PP&L proposes to offer other electric space heating customers is not supported by differences in cost, and that this service is also subsidized.

Q. WHAT COMMISSION ACTIONS DO YOU RECOMMEND?

A. Since 1984, RTS customers have been heavily subsidized. As a result, PP&L has been able to convert customers from oil heat to off peak electric heat. The only way in which CEPFOD members can regain these customers is if the subsidies are eliminated. I recommend the Commission consider the complete elimination of the RTS rate. The principal draw back to elimination is the investment which PP&L has caused ratepayers to make in order to qualify for the RTS rate. However, with RTS subsidies and incentive payments, most RTS customers recover their added investment within 5 years. Therefore, the focus of concern should be on ratepayers who have been on the RTS rate for less than 5 years. The existing tariff already contains a provision for monthly refunds to such customers if the RTS rate is withdrawn. PP&L should provide such refunds for a period of up to 5 years (depending on the date when service was initiated) after the RTS rate has been withdrawn. In order to provide a smoother transition from RTS to RS or RTD service, I also recommend that refunds be paid to all RTS customers for a minimum of three years following the date of the Commission's order in this case.

Q. SHOULD PP&L BE PERMITTED TO RECOVER THE COST OF THESE REFUNDS FROM RATEPAYERS?

A. No.

Q. WHAT ACTION DO YOU RECOMMEND IF THE RTS RATE IS NOT ABOLISHED?

A. In order to minimize distortions resulting from the underpricing of RTS service, I recommend:

(a) no change in the current RTS customer charge;

(b) elimination of the unbilled 2 kW demand allowance for RTS usage; and

(c) an increase in the RTS energy charge sufficient to recover the remaining authorized increase in RTS revenues.

Because the RTS rate is so far below cost, I also recommend that:

(d) the Commission freeze access to the RTS rate; and

(e) limit access to the RTS rate for existing customers to the lesser of eight years of cumulative service or the useful life of their heating systems.

I also recommend that the process of moving rates for existing customers toward cost begin by increasing the RTS rate by the greater of 17.4 percent, or two times the system average increase ultimately approved by the Commission.

Q. DO YOU RECOMMEND ANY ADDITIONAL COMMISSION ACTION IF THE RTS RATE IS NOT ABOLISHED?

A. Yes. PP&L has spent millions of dollars to aggressively promote RTS service despite knowing that the rate did not recover the cost of providing service, and that RTS service is not a cost effective demand side management tool. The purpose of this marketing campaign was to maximize sales and market share, and to discourage the availability of competitive service. Other rate classes should not be held responsible for the RTS revenue deficiency caused by the conduct of PP&L. If the RTS rate is not abolished, the entire RTS revenue deficiency that remains following the increase in RTS revenues authorized in this case should be absorbed by PP&L.

Q. DOES PP&L' CLASS COST OF SERVICE ANALYSIS PROVIDE A REASONABLE MEASURE OF THE COST OF SERVING THE RTS CLASS?

A. No. Based on my review of Mr. Kleha's cost of service study, I conclude that the Company's analysis (a) allocates too large a share of distribution investment and expense based on the number of customers served, and (b) does not accurately represent the causation of a majority of administrative and general (A&G) expenses. As a result, the RTS subsidy indicated in PP&L's Analysis is understated by about $4 million.

Q. WHAT ADJUSTMENTS TO PP&L'S ANALYSIS DO YOU RECOMMEND?

A. The principal adjustments that I recommend are:

1. rejection of PP&L's minimum system analysis of distribution transformers, poles, conduit, and conductor. These costs are predominantly demand rather than customer related. PP&L's proposal to treat over 64 percent of secondary distribution investment as customer related is inconsistent with the actual causation of associated costs.

2. rejection of PP&L's proposal to treat most administrative and general (A&G) expenses as a payroll related cost. Instead most A&G expenses should be treated as overheads, and allocated on the basis of responsibility for the sum of all production, transmission, distribution, and customer (PTDC) related costs excluding fuel expense.

These, and certain other adjustments that I recommend tie the allocation of costs more closely to cost causation, and recognize management's responsibility for the efficient use of all resources rather than labor alone.

Q. HAVE YOU ALSO EVALUATED PP&L'S RECOMMENDATIONS REGARDING THE STRUCTURE OF THE RATE FOR RS SERVICE?

A. Yes. With respect to the structure of the RS rate, I recommend:

(a) an increase in the customer charge that is smaller than proposed by PP&L;
(b) rejection of PP&L's proposal to introduce a third block in the rate; and
(c) no change in the current RS tail block differential of $.0194 per kWh.

Q. HAVE YOU PREPARED ANY SCHEDULES OR EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Schedule A summarizes my analysis of the cost incurred by PP&L in providing RS and RTS service. I have also prepared two volumes of exhibits. Volume I consists of PP&L responses to discovery that I have relied on in the preparation of my testimony. Volume II consists of documents that relate to the pricing and marketing of RTS service. These documents were produced by PP&L in civil litigation.

III. Regulatory Treatment of the RTS Revenue Deficiency

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the cost and effectiveness of PP&L efforts to promote RTS service. I also review studies prepared by PP&L to determine if the Company's marketing efforts were justified. I examine this issue from both an embedded cost and a demand side management (DSM) perspective. I conclude that the Company's promotion of RTS was not in the best interest of ratepayers or society, and was instead motivated by a desire to maximize kWh sales, maximize market share, and increase barriers to the entry of potential competitors.

Q. WHAT COMMISSION ACTION DO YOU RECOMMEND?

A. Both my analysis of costs and the class cost of service study filed by PP&L indicate that a large RTS revenue deficiency exists. I recommend that PP&L be required to absorb the difference between RTS revenues and the cost of providing RTS service, and that none of this revenue deficiency be shifted to other rate classes.

A. The Marketing of RTS Service[1]

Q. WHY DID PP&L INTRODUCE RTS SERVICE?

A. When RTS service was introduced, PP&L's primary objective was to offer a rate that would allow the Company to expand market share in the residential space heating market.

> The impact of lower fossil fuel prices on saturation will depend largely on the length of time current low pricing levels remain in effect. PP&L's standard residential rate cannot compete on a price only basis with either gas or oil in the heating fuel market.
>
> In order to maintain our large share of the market, we must continue to be innovative and receptive to the needs of the residential marketplace. Once a homeowner decides to install a fossil-fuel heating system, we

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[1] Documents referenced in Section III were produced by PP&L in response to discovery in Yeager's Fuel, Inc, et al v. PP&L (USDC, EDPa, CA #91-5176) and Loch Boiler Sales & Service Co. v. PP&L (USDC, EDPa CA #92-2359).

> have lost that customer for the life of the heating system or twenty (20) years. (Ex. 2, DM 064165:1986)

In 1986, PP&L was enjoying considerable success in the Company's efforts to market electric space heating service.

> PP&L's marketing efforts in the residential sector have resulted in a commanding share (85% in the first quarter, 1986) of all new dwelling units utilizing electric space and water heating. Marketing goals for electric heat saturation are being exceeded but there is cautious optimism. Current market share of new units now being connected is single - 87%, town - 95%, apartment - 77% and mobile home - 33%. The present fossil fuel pricing situation poses great challenges to maintaining saturation levels. We are seeing an increase in the number of homes planning to use fossil fuels as their heating fuel source on new service requests. (Ex. 2, DM 064165:1986)

However, declining fossil fuel prices were perceived as a threat to the Company's marketing goals.

> Continuing decline in fossil fuel prices will have negative impact on our electric heat saturation. At the present, our standard residential rate cannot compete on a price only basis with gas or oil in the heating market. We have already seen an increase in the number of new connects planning to use gas or oil as the heating fuel. (Ex. 2, DM 064173:1986)

RTS service provided PP&L an opportunity to gain market share by selling electricity below cost, and to disguise rate discounts as a demand side management tool.

Q. DOES THE RTS RATE SERVE ITS INTENDED PURPOSE?

A. Yes. Because <u>all</u> RTS usage is priced at a discounted rate, customers receive a significant discount on both space heating and other usage. An average RTS customer uses about 2.6 times as much energy as an average RS customer. RTS customers are large users throughout the year. Outside the space heating season, the average RTS customer uses 2.4 times as much energy as a non-space heating RS customer, and all of this usage is sold at a discount. If non-space heating RTS usage is repriced at the rate for RS service, an RTS customer's incremental cost for space heating is $.02 per kWh, an amount that is not even sufficient to recover incremental fuel expense. In contrast, the current tail block rate for RS service is $.0636 per kWh. RTS customers receive a 68 percent effective discount on their space heating service.

Q. HAS PP&L EXPENDED SIGNIFICANT RESOURCES IN ORDER TO MARKET RTS SERVICE?

A. Yes. Documents supplied by PP&L in response to discovery (see footnote 1) indicate that PP&L spent over $20 million between 1987 and 1991 in order to promote RTS service. (Ex. 3, DS 0067702:1991)

Year	RTS Total Cost	# Customers	Cost/Customer
87	3,799,740	1697	2239
88	3,889,448	2014	1931
89	5,173,032	2246	2303
90	3,937,450	1543	2551
91	3,717,000	1600	2323

PP&L's response to CEPFOD 33 indicates that an additional $4.3 million was spent between 1992 and 1994, and that RTS promotional costs during the test year were about a million dollars.

Q. WHAT TYPES OF EXPENDITURES WERE MADE IN ORDER TO PROMOTE RTS?

A. PP&L has paid incentives of $250 to $1250 to defray the added cost of installing storage capacity, provided grants of up to $1000 when electric service upgrades were required to accommodate "off-peak" storage, offered interest rate subsidies for loans used to finance conversions, and offered incentives to contractors and employees when marketing information or effort led to the conversion of existing fossil system to an electric storage system.

Q. DO THE DIRECT COST OF MARKETING RTS SERVICE ACCURATELY MEASURE THE COSTS OF PROMOTING THIS SERVICE?

A. No. A more substantial cost is the revenue shortfall created by the RTS discount. As discussed below, PP&L's marketing efforts have also resulted in a substantial net cost to society. If the Company's revenue spread and rate design proposals in this case are adopted, this marketing effort will also impose a significant net cost on non-participating customers.

Q. WAS THE DISCOUNTING OF PRICES FOR ALL RTS USAGE AN IMPORTANT PART OF PP&L'S EFFORT TO PROMOTE RTS SERVICE?

A. Yes. A "fact sheet" produced by PP&L in 1988 emphasized that a significant benefit of switching to the RTS rate was the discount that customers would receive on all of their electricity use.

> FACT #2: PP&L's money-saving RTS (Residential Thermal Storage) rate is about 40 percent lower than the regular residential rate. Customers with Nite-Saver electric storage heat, including the Heat Pump Plus, pay the low rate for <u>all the electricity they use in the home</u>, not just the heating.
>
> FACT #3: A home's total energy use determines its utility bills. On the RTS rate, customers can enjoy <u>lower overall energy costs than with natural gas heat</u>, because they pay the low RTS rate for all the electricity they use. (Ex. 4, DM 053942:1988)

Q. DID PP&L VIEW ITS EFFORTS TO MARKET RTS SERVICE AS A SUCCESS FOR THE COMPANY?

A. Yes. PP&L has received national recognition for the success of the Company's efforts to promote electric space heating. In 1988, PP&L described the Company's marketing efforts as follows:

> PP&L has been actively pursuing storage heating installations since 1982 and since that time storage heating market share has grown to 13 percent of new electrically heated homes. This is the highest new home saturation of any utility in the nation but only one-half the way to PP&L's objective of 25 percent included in our Least Cost Plan. (Ex. 5, DM 053591:1988)

Q. SHOULD THE COMMISSION VIEW PP&L'S MARKETING EFFORTS AS A SUCCESS STORY?

A. No. Space heating sales under the RTS rate does not even recover fuel costs and RTS service should not be included in PP&L's portfolio of cost effective DSM programs. Studies prepared by PP&L in the 1987-1991 time frame indicate that the interests of both society and non-participating customers would have been better served if the RTS marketing program had been abandoned. In 1988, PP&L had determined that the Company's efforts to promote RTS service were not justified.

> A decrease in the emphasis on RTS systems could defer the need for additional resources, including NUG (Non Utility Generation) as installed capacity or new supply-side resources.
>
> The RTS programs were developed to provide customers with the benefits of lower cost operation during off-peak periods and also to manage peak demand growth while increasing sales.
>
> As these programs succeed in the marketplace, there will be less benefits available because the off-peak cost advantages will be reduced.
>
> A strategy that can be applied to limit the growth of the RTS systems as the cost advantages diminish involves first removing the existing grant program and then, only if necessary, restricting the rate incentive to existing customers. (Ex. 6, DM 0136669:1987)
>
> . To achieve increased sales, other marketing programs could be emphasized.

Yet, PP&L opted to

> Continue the current marketing and economic development programs in the <u>near-term</u> to achieve the benefits of additional sales. (Ex. 6, DM 0136670:1987)

This decision was made despite the fact that promotion of RTS service would be ultimately harmful to other rate classes, potentially harmful to shareholders, and result in the accelerated addition of capacity to the system. PP&L's promotion of RTS has been a marketing "success", but a DSM and ratemaking failure.

B. Embedded Costs

Q. DO RTS REVENUES RECOVER COST OF SERVICE?

A. No. As discussed in Section III below, both my analysis of cost and the class cost of service study filed by PP&L demonstrate a large revenue deficiency for RTS service.

Q. DID PP&L KNOW THAT RTS SERVICE DOES NOT RECOVER THE COST OF PROVIDING SERVICE PRIOR TO THE FILING OF THIS CASE?

A. Yes. PP&L has recognized RTS as a subsidized service for years.

> The results of applying the PUC Methodology to the SESS program are provided in the PUC's format on Table 4B, with additional detail on Table 4C. As shown, the SESS program is expected to provide present

> worth benefits to the participant. The non-participant and PP&L, however, do not benefit. This is due to the fact that the reduction in PP&L's CSO is minimal. The increase in off-peak energy consumption significantly offsets any decrease in on-peak energy consumption due to the SESS heating storage losses. Since the non-participant's negative net present value is substantial, the program is a net cost to all ratepayers as a whole. (Ex. 7, DM 046902:1985)

An analysis of earned returns prepared by the Company in 1989 indicated that the earned return for RTS service was significantly below system average. The estimated return on equity for the RTS class was negative, and return on equity was projected to deteriorate significantly between 1989 and 1994. (Ex. 8, DS 0115985). The 1989 analysis concluded that "severe imbalances will exist by rate class and sub-rate class by 1994." (Ex. 8, DS 0115988).

Q. WHAT DO YOU CONCLUDE REGARDING PP&L'S DECISION TO CONTINUE TO PROMOTE RTS?

A. From an embedded cost perspective, promotion of RTS was imprudent. PP&L was spending over $2,000 per customer to switch customers from either baseboard (40 to 50 percent of new RTS load) or fossil systems at a time when each customer addition resulted in a present value revenue deficiency of $5,000 to $7,000. (Ex. 3, DS 0067699:1991; Ex. 9, DS 0067707:1991)

Q. DID THE STUDIES PREPARED BY PP&L IN 1989 INDICATE THAT RTS WAS THE ONLY SUBSIDIZED RESIDENTIAL SERVICE?

A. No. Past and projected returns for RS space heating customers were also estimated to be below the system and residential class average rates of return. (Ex. 8, DS 0115986:1991) Based on these findings, it was expected that both the RTS rate and the structure of the RS rate would be challenged in PP&L's next rate case.

C. RTS As A Demand Side Management Tool

Q. CAN THE RTS RATE BE JUSTIFIED AS A COST EFFECTIVE DEMAND SIDE MANAGEMENT PROGRAM?

A. No. When the Commission approved the RTS rate in 1984, a tenuous case may have existed in support of RTS service as a demand side management tool. However, PP&L has known for years that promotion of RTS service would result in a net increase in system peak demand, an increase in system revenue requirement, and a large and increasing RTS revenue deficiency that would have to be financed by subsidies from other classes or from shareholder profits. Despite this knowledge, PP&L has not ceased its efforts to promote RTS service. (CEPFOD 33)

Q. HAS THE DECLINE IN MARKETING EXPENDITURES SINCE 1989 AFFECTED GROWTH IN THE NUMBER OF CUSTOMERS TAKING RTS SERVICE?

A. Yes. As indicated in Table 1, RTS customer growth tracks marketing expenditures closely.

Table 1[2]

	Marketing Expenditures (000)	Customer Growth
1989	$ 5,173	2,164
1990	3,937	2,035
1991	3,303	1,769
1992	2,042	1,407
1993	1,291	973
1994	999	609
Total	$16,746	8,957

However, although RTS growth tapered off after 1989, customers attracted to the rate since 1988 account for over 60 percent of current RTS customer count (14,544).

[2] Sources: Ex. 1, Marketing expenditures: CEPFOD 33, Customer growth: OTS-RE-44D.

Q. WHAT EVIDENCE SUPPORTS THE ASSERTION THAT PP&L HAS KNOWN FOR YEARS THAT RTS IS A DSM FAILURE?

A. A least cost planning study prepared by PP&L in 1987 considered several demand scenarios. The base case plan assumed removal of "all impacts of PP&L's current marketing, economic development, and conservation programs in 1987". (Ex. 10, DS 018504). Both supply and demand side options were ranked on a scale of 0 to 10 within each of four screening categories (economic, sociopolitical, technological, and service to customers). The lowest ranking options were the addition of generating capacity, and marketing options that included water source heat pumps and Heat Pump Plus. (Ex. 10, DS 018533).

Q. WHY IS THERMAL STORAGE AN UNATTRACTIVE RESOURCE MANAGEMENT TOOL?

A. PP&L is a winter peaking utility, and the Company's peak day load is relatively flat with mid-day and nighttime valleys. RTS reduces demand diversity because it concentrates the maximum usage of customers in the evening and nighttime hours. In addition, RTS increases a customer's maximum demand because added electricity is used during the evening and night time hours in order to store energy for later daytime use.[3] Also, because of storage losses and a tendency for customers to turn up their thermostats in response to the availability of "cheap" energy, RTS results in a net increase in the total amount of energy that customers purchase. (Ex. 7, DM 046901) By pricing RTS below cost, PP&L not only encourages customers to switch to storage service, but to also increase their demand and total energy use.

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3 For customers choosing among electric heating options, estimated maximum demands are:

Ceramic storage	16.5 kW
Heat Pump Plus	9.6 kW
Baseboard	6.8 kW (approximate)

(Ex. 6, DM 0136677:1987)

Q. HAS THE RTS CLASS BEEN A SIGNIFICANT CONTRIBUTOR TO SYSTEM PEAK?

A. Yes. As indicated in Table 2, the importance of the RTS contribution to system peak depends on whether system peak occurs during the morning or evening hours.

Table 2

Year	Peak Hour	Peak Demand (kW)[4] System	RTS
1991	7-8 AM	5,365,487	36,439
1992	5-6 PM	5,674,025	190,148
1993	7-8 AM	5,801,467	54,779
1994	6-7 PM	6,075,629	257,775

Although the contribution of RTS to system peak is unpredictable, PP&L's response to OTS-RS-9D indicates that future test year design day demand assumes a 265 MW RTS contribution to system peak. Thus, although the RTS contribution to actual peak demand is unpredictable, PP&L must plan based on the assumption that the peak will occur during the evening hours, and that the RTS peak will coincide with the system peak.

Q. ARE THERE TESTS BY WHICH DSM PROGRAMS ARE COMMONLY EVALUATED?

A. Yes. Among the efficiency tests by which DSM programs are evaluated are:

1. Participant costs and benefits;
2. Non-participating ratepayer costs and benefits; and
3. Societal costs and benefits.

Q. DOES THE RTS PROGRAM PASS ANY OF THESE TESTS?

A. Yes. Because RTS service is so heavily discounted, it passes the participant test. However, participants benefit only because all of their usage is served at a rate that fails to recover cost.

[4] Source: OCA III-15.

Q. DOES RTS PASS THE TEST OF NET BENEFITS TO NON-PARTICIPANTS?

A. No. Any benefit that RTS may provide with respect to system revenue requirement is substantially smaller than the subsidy that is required in order to make RTS service attractive. Ratepayer harm will result if the cost of this subsidy is passed through to non-participants.

Q. DOES RTS PROVIDE NET BENEFITS TO SOCIETY?

A. No. The magnitude of net social loss varies depending on whether the customer would have installed a fossil system, a baseboard electric system, or a conventional heat pump. However, in all cases, there is a net social cost. PP&L analyses regarding RTS costs and benefits arrived at the following conclusions with respect to customers that choose RTS rather than a fossil system:

> When the RTS program influences customers to choose RTS rather than a fossil system, PP&L revenue requirements are increased.
>
> Energy costs are increased from higher amounts of kWh sales (an average general residential customer with a single family home uses about 9000 kWh/yr compared to about 26,000 kWh for an RTS customer).
>
> PP&L's capacity obligation to PJM is unchanged because an RTS customer and a general residential customer contribute about the same demand to PP&L's peak. (Ex. 9, DS 0067705:1991)

The claimed absence of harm as a result of the increase in demand associated with RTS was contingent upon PP&L remaining a daytime peaking utility. By 1987, and certainly no later than 1991, PP&L had determined that promotion of RTS would have caused a shift in the time of peak demand, and that RTS would result in a net increase in system peak demand.

> RTS systems currently operate in a fashion that contributes load to PP&L's 5 pm to 9 pm evening peak period. Continued promotion of RTS Systems could contribute to a more frequent occurrence of the system peak hour within this time period. New options identified by the RTS Task Force are to shift RTS system loads out of the 5 pm to 9 pm evening peak time period. (Ex. 11, DM 0137410:1991)

Q. WAS IT LIKELY THAT THE RTS PEAKING PROBLEM COULD BE SOLVED BY ADDITIONAL LOAD MANAGEMENT INITIATIVES?

A. No. The prospects for mitigating the RTS peaking problem by managing RTS loads were uncertain, likely to be costly in the retrofit segment of the market, viewed as a potential source of customer discontent, and of questionable efficacy under design day conditions. (Ex. 6, DM 0136670:1987; Ex. 11, DM 0137437-DM 0137448:1991)

Q. DOES THE SITUATION DIFFER IF THE CUSTOMER'S NEXT BEST ALTERNATIVE WAS ELECTRIC BASEBOARD HEAT?

A. Yes, but not by much.

> Adding RTS customers whose alternative was baseboard or heat pump results in the following effects:
>
> PP&L revenue requirements are reduced by about $2000 per customer (20 year cumulative present value), as discussed in the previous section.
>
> PP&L revenues are reduced by about $7000 per customer (20 year cumulative present value) as a result of the lower RTS rate.
>
> Because the amount of lost revenues exceeds the reduction in revenue requirements, over the long-term PP&L would need to recover the difference from rate payers or reduce the rate of return to investors.
>
> Consequently, when new customers are influenced to install RTS instead of baseboard or heat pump PP&L needs to recover about $5000 (present value) per RTS customer in additional rate revenue from other customers over 20 years. (Ex. 9, DS 0067709:1991)

Even for baseboard to RTS conversions, other ratepayers are harmed because the discounts offered far exceed potential reductions in system costs.

Q. DOES THE $2,000 REDUCTION IN PP&L REVENUE REQUIREMENT CITED IN YOUR PREVIOUS ANSWER DEMONSTRATE A SOCIETAL BENEFIT EVEN IF OTHER RATEPAYERS ARE HARMED?

A. No. Although PP&L revenue requirements may be reduced under a baseboard to RTS scenario, this does not imply a net social benefit because it does not account for the added cost incurred by the customer to install storage capacity. PP&L estimated that storage costs would add $2310 to the cost of an RTS customer's heating system in 1985, and this cost was expected to escalate at 5.5% per year. (Ex. 7, DM 046902:1985) Even if the RTS peaking problem could be solved, potential system benefit is less than the increase in participant cost that results from switching customers from a conventional to an RTS eligible system. Even under a best case scenario, RTS imposes a net cost on society.[5]

Q. WHEN DID PP&L DETERMINE THAT PROMOTION OF RTS WOULD RESULT IN A NET INCREASE IN PEAK DEMAND?

A. The RTS peaking problem was known to exist in 1987.

> Continuing today's marketing programs and achieving the goals for the Residential Thermal Storage (RTS) system, described on page 7, through the <u>long-term</u> beyond 1995 will:
>
> Result in a rate of peak demand growth that advances the need for additional resources,
>
> Increase revenue requirements per KWH,
>
> Increase the need for additional distribution facilities.
>
> The achievement of the currently established RTS marketing goals is responsible for the significantly increased peak demand and the shift to nighttime peak demand beyond 1995.
>
> The magnitude of the peak demand and not the timing (daytime or nighttime) is of primary importance. (Ex. 6, DM 0136667:1987)

Despite recognition of the RTS peaking problem, PP&L continued to promote the rate.

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[5] PP&L's 1994 DSM filing includes the following benefit to cost ratios for electric thermal storage:

	Ratio of Benefits to Costs
Participants	2.24
Utility	.85
Non-participants	.17
Total resources	.31

(CEPFOD 42, Attachment 3, page 2)

Q. PROMOTION OF RTS RESULTS IN A SHIFTING OF LOAD FROM THE DAYTIME TO THE EVENING AND NIGHTTIME HOURS. ISN'T THIS BENEFICIAL?

A. For some utilities, such a shifting of load might produce a benefit. However, PP&L's marketing of RTS was so aggressive that it not only shifted usage away from the daytime hours, it also shifted the time of system peak. This result was not only predictable, it was anticipated by PP&L. In 1987, least cost planning studies prepared by the Company concluded that:

> The predominant cause of the difference in system peak demands of the two forecasts is the RTS systems. In the 9/86 "<u>Integrated</u>" Forecast:
>
> > Prior to 1995, peak demand is lower due to the <u>reduced daytime</u> demand caused by the substitution of conventional heating systems with RTS systems in the new home market.
> >
> > After 1995, peak demand is higher due to the <u>increased nighttime</u> demand contribution of these units in the new home and existing home conversion markets. (Ex. 6, DM 0136674:1987)

In 1987, PP&L knew that it had a winter peaking problem, and that RTS would contribute to this problem. Despite this knowledge, the Company continued to promote RTS.

Q. IS THE ONLY HARM ASSOCIATED WITH THE PP&L'S PROMOTION OF RTS THE BURDEN THAT THIS SERVICE IMPOSES ON OTHER RATE CLASSES?

A. No. By promoting RTS, PP&L encouraged the development of a supporting infrastructure.

> To accomplish the current RTS goals, an infrastructure outside of PP&L is being developed to manufacture, distribute, sell, install and maintain RTS systems. (Ex. 6, DM 0136668:1987)

A cost based rate for RTS service would not be competitive with alternate fuels.

> If RTS rates were adjusted to achieve the same rate of return as RS rates, the total estimated cost for RTS systems becomes higher than that of alternative electric or fossil heating systems. (Ex. 11, DM 0137415:1991)

A movement of rates toward cost of service would likely result in the stranding of third party investments that were based on PP&L's decision to offer a promotional rate, but were inconsistent with economic realities.

> As this infrastructure develops, it may be difficult for PP&L to reduce RTS installations because considerable non-PP&L resources have been committed to this effort.
>
> Of specific concern is the effect on local dealers and installers. (Ex. 6, DM 0136670:1987)

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE VALUE OF RTS AS A DEMAND SIDE MANAGEMENT TOOL.

A. By no later than 1987, PP&L knew that RTS was not a viable DSM tool, and that continued marketing of RTS would impose a net cost on non-participating customers and society. However,

> Termination of the RTS rate would severely damage PP&L's credibility with customers and allies, and would negatively impact morale of our employees, especially in the Marketing Department. The impact would be similar to the one created by the withdrawal of the RH rate for which PP&L is yet to recover. (Ex. 12, DB 0155443:1991)

The conflict between least cost planning and marketing goals and strategy was resolved in favor of marketing.

D. Shareholder Impact

Q. HAS PROMOTION OF RTS ENHANCED SHAREHOLDER PROFITS?

A. No, at least not in the short run. For example, in 1989 RTS promotion costs totalled $5.2 million. The total "margin" on RTS sales was estimated to be $3.8 million. However, the $1.4 million RTS loss implied by the difference between RTS promotion cost and "margin" RTS does not account for the margin that PP&L would have earned ($3.6 million) on the sale of electricity if the "normal" needs of RTS customers were served under the RS rate. After accounting for program costs and the revenues that would have been received in the absence of an RTS rate, PP&L estimated the net 1989 loss of margin associated with RTS service to be $5.3 million. (Ex. 13, DM 0136730:1991)[6]

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[6] A 1992 analysis indicates a small five year positive margin for RTS after accounting for the tax deductibility of marketing costs. However, both the five and ten year present value of RTS margins is less that corresponding margins for general residential and RS heating customers. (CEPFOD 42, DM 0139547:1992) The study concludes that "Marketing costs

Q. WHY WOULD PP&L PROMOTE A SERVICE THAT RESULTED IN A NET LOSS OF MARGIN, AND FOR WHICH THE INDICATED RETURN ON COMMON EQUITY WAS NEGATIVE?

A. Comparative analysis of space heating costs prepared by PP&L in the 1987-1989 time frame (Ex. 14, DM 0126075; Ex. 15, DM 0066953) indicated that both oil and natural gas were less costly than electric space heating unless a customer took service under the RTS rate. PP&L appears to have been preoccupied with maximizing sales and market share rather than ratepayer benefit or short term profits.

Are less profitable market segments valuable if they help block the competition's market development?

Through a multi-market electric heat strategy, PP&L has limited the extension of gas lines, thus increasing sales in all segments. (Ex. 16, DM 055972:1989)

The potential for increased profits as a result of RTS promotion also existed if:

1. the RTS revenue deficiency could be shifted to other rate classes in future rate cases (Ex. 13, DM 0136726:1991; Ex. 3, DS 0067699:1991);
2. RTS promotional costs could be targeted more precisely at customers that might otherwise opt for fossil fuel service (Ex. 13, DM 0136743:1991);
3. excess capacity disallowances were reduced as a result of more rapid growth in peak demand; and
4. PP&L were permitted to defer and eventually recover RTS promotional costs. (ibid)[7]

By stimulating sales growth, RTS also provided some protection from revenue shortfalls that might result from increased competition for industrial load. (Ex. 10, DS 018561:1987)

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to support the RTS Program must be reduced to minimize the earnings reduction.' (DM 0139552:1992, CEPFOD 42)

7 In 1994, PP&L requested deferred accounting treatment of all promotional costs associated with electric thermal storage (CEPFOD 42 Attachment 3, page 3).

Q. MIGHT PP&L ARGUE THAT IT HAD NO CHOICE OTHER THAN TO OFFER A DISCOUNTED RATE IN ORDER TO MEET THE COMPETITION?

A. No. From both a societal and a ratepayer perspective, prudent management would have conceded market share in those segments of the market where PP&L lacked a cost advantage. PP&L chose to respond to competitive pressure by offering a rate that was below cost in the hope that future ratepayer subsidies, higher RTS rates, or larger market share might allow the Company to recoup its losses.

E. Recommendation

Q. WHAT ACTION DO YOU RECOMMEND REGARDING THE RTS REVENUE DEFICIENCY?

A. PP&L has known for years that the RTS rate was unjustified. To the extent that the RTS rate has resulted in short term losses to shareholders, this result was known to PP&L management.

> When the RTS program costs more than it saves, subsidies must come from either investors (in the form of lower return on investment) or other ratepayers in the form of higher rates. (Ex. 9, DS 0067705:1991)

> The overall effect of influencing customers to choose RTS rather than alternative electric or fossil heating systems is estimated to be lower short-term earnings and a higher average price to non-RTS customers. (Ex. 13, DM 0136724:1991)

PP&L now proposes to shift responsibility for RTS shortfall from shareholders to ratepayers. The Commission should refuse to bail PP&L out of the costs of an uneconomic marketing program, and require that RTS losses continue to be absorbed by shareholders.

IV. Class Cost of Service

Q. PLEASE DESCRIBE THE PROCESS REQUIRED IN ORDER TO PREPARE A COST OF SERVICE STUDY.

A. In general, electric utilities provide four basic services to customers:

1. the production of electricity;
2. the provision of transmission service that links generating facilities with local centers of load;
3. the provision of local distribution service required to reach those customers that are served at lower than transmission voltage; and
4. the servicing of customer accounts.

The first step in a cost of service study is to divide the total cost of providing service among these four basic functions.

Q. ARE ALL OF THE COSTS OF PROVIDING ELECTRICITY SERVICE READILY ASSIGNED TO THE PRODUCTION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER FUNCTIONS?

A. No. Certain administrative and general (A&G) overheads do not fall neatly into any of these four categories. As a result, these overheads are usually divided among functions in proportion to some measure of production, transmission, distribution, and customer (PTDC) related costs.

Q. IS ANY FURTHER PROCESSING OF COST DATA REQUIRED ONCE COSTS ARE DIVIDED AMONG THE PTDC FUNCTIONS?

A. Yes. It is generally accepted practice to distinguish between costs incurred to serve the maximum demands that classes impose on the system (demand related costs), costs that are incurred to serve system energy requirements throughout the year, and costs that vary with the number of customers served rather than demand or energy usage. However, the appropriate division of costs between the demand, energy, and customer classifications is not always obvious. For example, the amount of PTD capacity required depends on maximum system, class, and customer demands, but the type and cost of plant installed is also influenced by the objective of lowering the total cost of producing and delivering energy. As a result, consideration of both maximum demand and energy usage throughout the year influence a utility's decisions regarding the size, type and cost of production, transmission and distribution plant installed.

Q. IS THE DISTINCTION BETWEEN DEMAND, ENERGY AND CUSTOMER RELATED COSTS IMPORTANT?

A. Yes. Load characteristics and customer count differ significantly among rate classes. For example, based on the allocation factors proposed by PP&L the large power classes account for 33 percent of energy, 28 percent of demand, and less than one percent of the total number of customers served. As a result, the share of a cost assigned to the large power classes depends heavily on the decision made regarding the classification of that cost as demand, energy, or customer related.

Q. WHAT GUIDELINES ARE APPROPRIATE FOR THE PURPOSE OF EVALUATING A COST OF SERVICE ANALYSIS?

A. With the exception of A&G overheads and the division of certain distribution costs between primary and secondary service, the division of costs among functions is largely a matter of accurate bookkeeping. Cost classification – the division of functionalized costs between the demand, energy, and customer categories – is a central issue. It is the classification stage at which regulators must evaluate the motives that drive utility decisions, and the costs and benefits that flow from those decisions. In this phase of a cost of service analysis the key questions are the causation of costs and the benefits that ratepayers receive. If a cost is incurred exclusively for the purpose of serving peak demands, it should be classified as demand related, and allocated based on responsibility for system peaks. However, if the justification for an investment or expense item is the provision of a reliable, low cost supply of energy throughout the year, responsibility for associated costs is best measured by class responsibility for the energy requirements of the system rather than class responsibility for system peaks.

Q. IS MR. KLEHA'S ALLOCATION OF COSTS BASED ON A DETAILED AND UTILITY SPECIFIC ANALYSIS OF COST CAUSATION?

A. No. Mr. Kleha's analysis does not accurately reflect the composition or causation of several costs. The alternative analysis that I sponsor:

1. reduces the weight assigned to customer count in the Company's allocation of distribution plant and expense, and
2. provides a more reasonable basis for allocating A&G overheads among rate classes.

My analysis of cost provides greater recognition of cost causation, a more reasonable matching of costs and benefits, and a more equitable allocation of costs among retail classes.

A. Intangible Plant

Q. HOW HAS MR. KLEHA ALLOCATED INTANGIBLE PLANT?

A. He allocates all intangible plant in proportion to PTDC payroll.

Q. IS PTDC PAYROLL A GOOD INDICATOR OF COST CAUSATION?

A. No. As indicated in Table 3, virtually all of the $21.9 million included in the intangible plant accounts consists of computer software.

Table 3
Intangible Plant (000)

Organization Costs	$ 476
Franchise Costs	147
Computer Software	21,280
Total	$21,903

Almost all of this software relates to engineering, and the management of production and transmission costs (CEPFOD 28). It would be reasonable to allocate investment in software in proportion to class responsibility for PTD plant, and to treat the remainder of intangible plant as a corporate overhead. PTDC payroll is a poor proxy for cost causation.

B. Production Plant and Expense

Q. WHAT FACTORS DETERMINE A COMPANY'S TOTAL INVESTMENT IN PRODUCTION PLANT?

A. In general, peak demand determines the amount of capacity required, but hours of service (expected energy production) determine the type of capacity installed. Most coal and nuclear generating units are built based on the expectation that energy related O&M expense savings will compensate for the relatively high construction cost of baseload capacity. When compared to baseload capacity, construction cost for peaking capacity is low. However high operating cost per MWh precludes exclusive reliance on combustion turbine units and other types of generating capacity with relatively low construction cost.

Large differences exist among generating unit types with respect to construction cost, O&M expense, and fuel expense. Because of these differences, an allocation method that looks solely at demand characteristics and disregards differences in technology and cost is unlikely to provide an assignment of investment and expense that is consistent with the actual causation of costs. Baseload generating capacity is two to six times more costly to construct than intermediate and peaking capacity (CEPFOD 13). Because a kW of coal or nuclear capacity contributes no more to system reliability during hours of peak demand than does a kW of combustion turbine capacity, the high relative cost of coal and nuclear capacity cannot be justified based solely on a need to serve system peaks. The construction of baseload capacity is justified only if (a) high fixed costs can be spread across many hours of operation, and (b) the cost per kWh of operating and maintaining these units is significantly lower than the corresponding costs for alternative capacity that is cheaper to build. Recognition of the tradeoffs that exist between investment and expense implies that a significant share of PP&L's investment in baseload capacity is related to average demand (energy) rather than peak demand.

Q. DOES MR. KLEHA'S CLASSIFICATION OF PRODUCTION INVESTMENT AND EXPENSE ACCOUNT FOR COST AND TECHNOLOGY DIFFERENCES AMONG GENERATING UNITS?

A. No. Mr. Kleha proposes that all investment in production plant and 61 percent of non-fuel production O&M expenses be classified as demand related. Because the decision to install baseload capacity is driven primarily by the need to serve hourly demand throughout the year, a large share of the ownership, operating and maintenance costs of this capacity should be allocated on the basis of average rather than peak demand.

Q. HOW DOES MR. KLEHA ALLOCATE DEMAND RELATED PRODUCTION COSTS?

A. He allocates demand related costs among rate classes in proportion to class contribution to the sum of the twelve monthly system peaks (12 CP).

Q. DOES THE 12 CP METHOD PROPOSED BY MR. KLEHA ACCOUNT FOR THE FACT THAT SYSTEM PLANNING DECISIONS ARE INFLUENCED BY BOTH ENERGY REQUIREMENTS AND PEAK DEMAND?

A. A 12 CP allocator does not explicitly recognize the distinction between investments that have been made to serve peak demand and investments that were made in an effort to minimize total production cost. However, in the case of PP&L, a 12 CP allocation of production plant investment strikes a reasonable balance between reliability costs, energy related investment, and the need to accommodate the scheduling of coal and nuclear outages during off-peak months.

C. Distribution Plant Investment and Expense

Q. PLEASE DESCRIBE THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT.

A. Mr. Kleha's analysis of distribution plant includes minimum system calculations through which he attempts to identify a portion of secondary distribution plant as customer rather than demand-related. In general, the percent of investment that Mr. Kleha attributes to a minimum system is calculated by:

a. determining the unit cost of the smallest pole, conductor or transformer that PP&L currently installs on the system;

b. multiplying the unit cost calculated in step (a) by the total quantity of poles, conductor, and transformers in service; and

c. dividing the hypothetical cost calculated in step (b) by actual gross investment for each plant account.

The results of step (c) are listed in Table 4 as the percent of distribution plant investment that PP&L attributes to a minimum system.

Table 4

Minimum System Composition and Cost

Account	Minimum System Equivalent	Percent of Secondary Plant
Poles and Towers	40' Wooden Pole	47%
Overhead Conductor	1/0 Triplex	65
Underground Cable	1/0 Triplex	37
Underground Conduit	Not specified	37
Transformers	10 to 25 kva	56
Services	#4 Triplex	92
Total Secondary Distribution Plant		64%

Q. DO YOU AGREE WITH PP&L'S CALCULATION OF MINIMUM SYSTEM COSTS?

A. No. For every plant account included in his minimum system, Mr. Kleha has chosen to represent required investment using plant costs that exceed the lowest cost plant that has actually been installed by PP&L (OSBA 28; CEPFOD 1, 30, 31, and 32). Mr. Kleha's quantification of minimum system costs also attributes higher cost to a minimum system than would result if he had used the zero intercept method of quantification.

Q. WOULD THE RESULTS OF MR. KLEHA'S ANALYSIS VARY SIGNIFICANTLY IF HE BASED HIS ANALYSIS ON MINIMUM PLANT SIZES ACTUALLY IN SERVICE ON PP&L'S SYSTEM?

A. Yes. For example, the weighted average cost of line transformers currently in service that are smaller than 10 kva is $200. Had Mr. Kleha based his estimate of minimum transformer costs on this average rather than the cost of 10 and 25 kva transformers, his estimate of "customer" related transformer investment would have fallen from 56 percent to 28 percent. Had he used the embedded cost of a 3 kva transformer, the minimum system share of transformer investment would have been only 13 percent.

Q. MR. KLEHA CLAIMS THAT HIS MINIMUM SYSTEM IS BASED ON THE MINIMUM SIZED FACILITIES THAT PP&L CURRENTLY INSTALLS WHEN A NEW CUSTOMER IS ADDED TO THE SYSTEM. IS THIS A REASONABLE BENCHMARK FOR CALCULATING MINIMUM SYSTEM COSTS?

A. No. Minimum system analysis is purely hypothetical, and purports to capture the cost that would be incurred to provide a customer with access to the system, but with no capacity to serve. When PP&L actually adds a customer to the system, it does so with the expectation that the customer will purchase electricity. The smallest facilities currently installed on PP&L's system are sized to serve PP&L's expectation of usage by the Company's smallest customers. If, for reasons unknown, PP&L were to construct a system that provided access but no load carrying capability, the facilities that PP&L would choose for this task would be based on the smallest and cheapest plant available, rather than PP&L's current minimum size standard for overhead and underground plant. Because current PP&L practice is based on the expectation that all customers will purchase some amount of electricity, current practice is not a reasonable benchmark for the purely hypothetical system that Mr. Kleha attempts to construct.

Q. WOULD RELIANCE ON OTHER MEASURES OF MINIMUM SYSTEM COST REDUCE THE SHARE OF DISTRIBUTION PLANT THAT MR. KLEHA CLASSIFIES AS A CUSTOMER COST?

A. Yes. The zero intercept method was proposed by PP&L in the Company's last rate case, and is often used by proponents of the minimum system concept in order to remedy the double counting problem that I discuss below. This method uses regression analysis to estimate the hypothetical cost of conductor and transformers with no capacity to carry load. Logically, the cost of such a hypothetical pole, line or transformer may be less than but cannot exceed the cost of the minimum capacity sizes actually installed by PP&L. If zero intercept costs were greater than the actual costs of minimum sized facilities, a prudent utility installing a hypothetical minimum system would opt for the lower cost alternative, and install a "minimum size" facility. Reliance on the zero intercept method would therefore reduce the share of investment that PP&L treats as a minimum system cost.

Q. ARE THERE OTHER DEFECTS IN PP&L'S ANALYSIS OF DISTRIBUTION PLANT AND EXPENSE?

A. Yes. PP&L's allocation of minimum system costs is also defective. Mr. Kleha treats minimum system costs as if they were the result of customer count. This is conceptually incorrect. The minimum system concept introduces a theoretical cost to a class cost of service without any clear evidence regarding the causation of this hypothetical cost. Dr. James Bonbright's critique of the minimum system concept is frequently cited by cost analysts:

> ...the annual costs of this phantom, minimum sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs... Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.
>
> What this last-named cost imputation overlooks, of course is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or

> per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system. (<u>Principles of Public Utility Rates</u>, pages 247-248)

The cost of a minimum distribution system is not closely related to either demand or customer count. These costs actually vary with (a) the number of customers served per pole, per mile of conductor, and per transformer, (b) safety and cost considerations, and (c) community standards regarding aesthetic acceptability. They represent an overhead that varies not with the number of customers served, but with less easily quantified class characteristics such as income and customer density.

Q. IS PP&L'S CLASSIFICATION OF MINIMUM SYSTEM COSTS CONSISTENT WITH EMPIRICAL STUDIES REGARDING THE CAUSATION OF DISTRIBUTION PLANT INVESTMENT?

A. PP&L has prepared no Company specific analyses that support Mr. Kleha's classification of distribution plant investment and expense. (CEPFOD 4). Empirical analyses have reported that distribution and customer sales accounts are closely correlated with load density, but not significantly affected by the number of customers served. ("Antitrust in the Electric Industry", by Leonard Weiss, in <u>Promoting Competition in Regulated Markets</u>, Phillips, Almarin, Ed., The Brookings Institution 1975, page 145.)

Q. DOES MR. KLEHA'S METHOD FOR QUANTIFYING MINIMUM SYSTEM COSTS CREATE ANY PROBLEMS REGARDING THE ALLOCATION OF DEMAND RELATED COSTS?

A. Yes. Mr. Kleha's analysis of minimum system costs causes demand allocators to "double-count" small customer responsibility for demand-related costs. The minimum size plant that PP&L uses to divide investment between the demand and customer classifications is capable of carrying some load. As a result, the cost of PP&L's "minimum" facility is not a pure customer cost. For example, Mr. Kleha's minimum system component of transformer investment accounts for 32 percent of installed capacity, and 56 percent of total gross investment. In order to account for the capacity built into a minimum system, demand allocators would need to be adjusted downward, with this adjustment to demand distributed among rate classes using the same factors used to allocate the minimum system share of investment attributed to customer count.

Q. HAS MR. KLEHA RECOGNIZED THE PROBLEM OF DOUBLE COUNTING?

A. It appears that Mr. Kleha has attempted to deal with the problem of double counting, but only with respect to his allocation of transformers and service drops. For these items of plant, he does not adjust demand allocators as I suggest, but instead adjusts the factors used to allocate the customer component of plant by assigning greater weight to general service customers.

Q. DO THE WEIGHTS THAT MR. KLEHA USES WHEN CALCULATING ALLOCATION FACTORS FOR "CUSTOMER" COSTS CURE THE DEFECTS IN PP&L'S MINIMUM SYSTEM ANALYSIS?

A. No. Table 5 compares (a) PP&L's allocation factors for transformers with (b) allocation factors calculated based on a minimum system consisting of 3 kva transformers and demand allocators that are adjusted to eliminate the problem of double counting, and (c) the NCP allocation factors that would apply if all transformer costs are classified as demand related.

Table 5
Alternative Transformer Cost Allocation Factors

	Transformer Investment Allocators		
	(a) PP&L	(b) Adjusted	(c)NCPDemand
Residential (RS)	.661	.571	.569
Residential (RTS)	.025	.042	.044
General Service (GS-1)	.097	.079	.078
General Service (GS-3)	.135	.253	.266
General Service (GH)	.020	.036	.038
Lighting	.062	.019	.005

Replacement of PP&L's minimum size transformers with a minimum cost (3 kva) transformer and adjustment for the load carrying capability of a 3 kva transformer reduces the share of demand related costs assigned to the RS, GS-1, and lighting classes, and significantly increases the share of demand related costs allocated to the RTS, GS-3, GH classes. With the exception of the lighting class, "Adjusted" allocators do not differ appreciably from an allocation of transformer investment based solely on demand.

Q. WHAT COMMISSION ACTION DO YOU RECOMMEND?

A. I recommend that the Commission reject PP&L' minimum system analysis of poles, conduit, conductor, and transformers, and classify all associated costs as demand related. By relying on a minimum system analysis, Mr. Kleha introduces a hypothetical cost for which causation is indeterminate, and quantification is a matter of judgment rather than fact. His classification and allocation of overhead and underground conductor fails to account for the load carrying capability of minimum sized facilities, and his classification of poles attributes more costs to a minimum system than would result if a pole size less than 40 feet were assumed. Mr. Kleha's analysis of minimum system costs adds complexity, subjectivity, and controversy to the issue of cost allocation, without the benefit of a tighter linkage with causation.

D. Administrative and General (A&G) Overheads

Q. HOW HAS MR. KLEHA ALLOCATED A&G EXPENSES?

A. With the exception of property insurance expense, Mr. Kleha allocates A&G expenses among rate classes in proportion to the sum of production, transmission, distribution and customer related (PTDC) payroll assigned to each class.

Q. IS MR. KLEHA'S ALLOCATION OF A&G EXPENSES REASONABLE?

A. No. I have examined the composition of expenses booked to Accounts 920, 923, 925, and 930. In combination with A&G supplies (Account 921), these expenses total $92 million, and account for most of the A&G expenses that are not directly related to plant or payroll.

Table 6
1994 A&G Expenses

Account	Description	Total Expense (000)
920	Administrative Salaries	$36,970
921	A&G Supplies	20,936
923	Outside Services	9,201
925	Injuries and Damages	7,128
930	Miscellaneous	17,460
Total		$91,695

Based on my analysis, I conclude that only a small share of the A&G expenses itemized in Table 6 actually relates to payroll. Most of these expenses represent general overhead. PP&L's allocation of Table 6 expenses based on payroll is inconsistent with actual cost causation.

Q. IS PAYROLL A GOOD PROXY FOR CLASS RESPONSIBILITY FOR GENERAL OVERHEADS?

A. No. A payroll allocator places undue emphasis on labor intensive activities such as meter reading, customer accounting, and customer service. This problem can be illustrated by comparing the shares of gross plant, rate base, O&M excluding fuel, and payroll that Mr. Kleha has allocated to the RS class.

Table 7
Residential (RS) Shares Per PP&L COSA

	RS Share
Gross Plant	44.9%
Rate Base	45.6
O&M Expense Excluding Fuel	43.9
PTDC Payroll	48.9

To the extent that A&G expenses actually vary with costs other than payroll expense, Mr. Kleha's allocation of these expenses is systematically biased against classes that are populated by relatively small customers.

Q. CAN YOU CITE SPECIFIC EXAMPLES OF A&G EXPENSE ITEMS THAT ARE RELATED TO REVENUE REQUIREMENT DETERMINANTS OTHER THAN PAYROLL?

A. Yes. A few examples are itemized below:

1. Expenses booked to Account 920 include accounting and tax related expenses (24 percent of the total) that are primarily plant rather than payroll related. Only *about nine percent of Account 920 expense actually relates directly to payroll.* (CEPFOD 17)
2. Less than 30 percent of expenses booked to Account 923 actually relates to payroll. Most of these expenses are actually general overheads such as legal services, corporate planning expenses, and audit fees. (CEPFOD 19)
3. Approximately 25 percent of expenses booked to Account 925 are the result of claims filed by individuals that are not PP&L employees. (CEPFOD 18) These expenses are general overhead rather than payroll related costs.
4. Among the expenses booked to Account 930 are EPRI dues, R&D expenditures, Board of Directors fees and expenses, expenses relating to the issuance of securities, and the cost of reports to shareholders. (1993 FERC Form 1, pages 335 and CEPFOD 20) None of these expenses relate directly to payroll.

Q. HOW SHOULD THE EXPENSES ITEMIZED IN TABLE 6 BE ALLOCATED?

A. Most of these expenses are general overhead. Rather than focusing on labor, O&M, or plant alone, general overheads should be allocated in proportion to total PTDC costs. This is the same procedure followed by the Company, except that the PTDC allocator that I recommend includes:

payroll and materials expense included in non-fuel O&M expense;
depreciation expense;
return; and
taxes.

The alternative that I recommend is a comprehensive measure of PTDC revenue requirement that avoids the systematic biases that may result when a single component of costs such as payroll or plant is singled out as the basis for allocating corporate overheads.

Q. IS THE TREATMENT OF A&G OVERHEADS THAT YOU RECOMMEND SUPERIOR TO THE COMPANY'S APPROACH?

A. Yes. Management's basic task is the efficient use of resources. These resources include not only labor and materials, but plant investment as well. Mr. Kleha assumes that all management overhead is related solely to payroll despite the fact PTDC payroll accounts for less than nine percent of PP&L's total PTDC revenue requirement. An allocation of A&G overheads in proportion to total direct PTDC cost is appropriate in order to recognize management's general responsibility for the efficient use of all resources required to provide service.

Q. IS THE TREATMENT OF GENERAL OVERHEADS THAT YOU RECOMMEND CONSISTENT WITH GENERAL ACCOUNTING PRACTICE?

A. Yes. Although the need to distribute overheads is less pressing in non-regulated industries, the allocation of overhead among product lines and divisions in proportion to total direct cost is a generally accepted method in industries that are not subject to comprehensive regulatory oversight. (Cost Accounting Standards Board, Cost Accounting Standards Guide, Commerce Clearing House, Inc., 1989, pages 3385-3387.)

Q. DO YOU RECOMMEND ANY CHANGES IN MR. KLEHA'S ALLOCATION OF GENERAL PLANT?

A. Yes. I recommend that costs associated with plant booked to Accounts 389, 390, and 391 also be treated as overhead. Like most Account 920 expenses, these investments are not related directly to payroll, and there is no reason to treat associated costs as labor related.

E. Conclusion

Q. HOW DO THE ADJUSTMENTS THAT YOU RECOMMEND AFFECT PP&L'S ANALYSIS OF THE COST OF SERVING RTS CUSTOMERS?

A. Although I have not prepared a comprehensive class cost of service analysis, I can approximate the affect of the adjustments that I recommend on the costs that Mr. Kleha allocates to the RTS class.

Table 8
RTS Cost of Service (000)

Cost of service per PP&L	$42,177
Reallocate distribution investment and expense	3,510
Reallocate A&G expenses	367
Incremental gross receipts taxes	182
Adjusted cost of service	$46,236

According to the Company's analysis, the increase in RTS rates required for full cost recovery is 113 percent. As indicated in Table 8 and Schedule A, the adjustments that I recommend add about $4 million to the costs that Mr. Kleha allocates to RTS service, and would support a 134 percent increase in current RTS revenues.

Q. DO YOU RECOMMEND A 134 PERCENT INCREASE IN RTS RATES?

A. Such an increase would be cost based, and it would mitigate the harm to competition and the harm to competitors that has resulted from the promotion of RTS service. However, such an increase would obviously cause considerable hardship for existing RTS customers. It would, therefore, be preferable to (a) eliminate the RTS rate, (b) move RTS customers to the RS or RTD rate, and (c) require PP&L to compensate customers that have been on the rate for less than five years.

Q. WHAT COMPENSATION WOULD RTS CUSTOMERS RECEIVE?

A. If the RTS rate is withdrawn, the RTS tariff requires PP&L to pay $50 per month to RTS customers that have been on the rate for less than five years. This payment continues until five years elapse from the customers initial date of service.

Q. WOULD ANY MODIFICATION OF THE COMPENSATION PROVISION OF THE RTS TARIFF BE APPROPRIATE IF THE RATE IS WITHDRAWN?

A. Yes. In order to reduce the problem of rate shock, it would be reasonable for all RTS customers to receive a $50 bill credit for a minimum of three years following the effective date of the Commission's order in this case.

Q. SHOULD PP&L BE PERMITTED TO RECOVER THE REVENUES THAT WOULD BE LOST AS A RESULT OF THE RTS BILL CREDITS THAT YOU RECOMMEND?

A. No. The cost of any RTS subsidy should be borne by shareholders.

Q. SHOULD THE COMMISSION ADOPT PP&L'S PROPOSED REVENUE SPREAD IF THE RTS RATE IS NOT WITHDRAWN?

A. No. Table 9 compares revenue deficiencies based on PP&L's cost of service study with the results of my analysis. It also summarizes PP&L's recommendation regarding residential revenues.

Table 9
(000 Omitted)

	Revenue Deficiency		PP&L Proposed Increases	
	Andersen	Kleha		Percentage Increase
Residential (RS)	$141,172	$178,665	$135,621	15.29%
Residential (RTS)	26,462	22,403	3,438	17.38
Total PA Retail		$257,926	$257,926	11.70%

The increase in RTS revenues proposed by PP&L is equal to 1.5 times system average and is only slightly higher than the increase proposed for RS service. In contrast, Mr. Kleha's allocation of costs indicates a required increase equal to 113 percent. If PP&L's allocation of costs and proposed revenue spread were adopted, the RTS subsidy would continue, and most of this subsidy would be at the expense of the GS-1 class. PP&L proposes a 3.9% increase in GS-1 revenues despite an indicated revenue surplus of $23.6 million (17 percent).

Q. WHAT ACTION DO YOU RECOMMEND IF THE RTS RATE IS NOT WITHDRAWN?

A. I have not analyzed PP&L's accounting case, and the only revenue requirement adjustment that I recommend relates to the RTS revenue deficiency. Even if the Commission were to find PP&L's claimed need for a revenue increase excessive, my findings regarding class cost of service cause me to recommend an increase in RTS rates that is no smaller than the 17.4% increase proposed by PP&L and that access to the RTS be frozen. If the RTS rate is not withdrawn, I also recommend that PP&L be required to absorb the difference between RTS revenues and the cost of providing RTS service.

V. Residential Rate Design

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I evaluate Mr. Kasper's recommendations regarding changes in the structure of PP&L's rates for residential service.

A. RTS Service

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING CHANGES IN THE RATE FOR RTS SERVICE?

A. Because the RTS rate is so far below cost, it is appropriate that an increase in the current rate focus on demand and energy charges, with no change in the current RTS customer charge. In order to minimize price signal distortion, I recommend:

1. no change in current RTS customer charge;
2. a reduction in the current subsidy to non-space heating RTS usage by eliminating the 2 kW demand exemption; and
3. recovery of the remainder of the increase in RTS revenues through an increase in the energy charge.

Q. SHOULD PP&L BE PERMITTED TO CONTINUE TO ADD RTS CUSTOMERS?

A. No. Because the RTS rate is so far below cost and ineffective as a demand side management tool access to the rate should be frozen.

Q. SHOULD CURRENT RTS CUSTOMERS BE PERMITTED TO TAKE SERVICE UNDER THE RATE?

A. Yes, but current customers should be permitted to remain on the rate for the <u>lesser</u> of eight years of cumulative service or the useful life of their heating systems. In order to permit a smoother transition from RTS to RS or RTD service, customers that have been on the RTS rate for five or more years should be permitted to remain on the RTS rate for three years following the date of the Commission's order in this case.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT RTS SERVICE BE LIMITED TO EIGHT CUMULATIVE YEARS OF SERVICE?

A. Studies prepared by PP&L indicate that five years of RTS service are required for a customer to recoup the added cost of storage. Eight years of service should, therefore, be sufficient to protect existing RTS customers from significant financial harm.

B. RS Service

Q. PP&L PROPOSES TO INCREASE THE CURRENT RS CUSTOMER CHARGE FROM $4.80 TO $7.20 PER MONTH. IS THIS PROPOSAL REASONABLE?

A. No. Mr. Kleha's estimate of RS "customer" costs is $17.51 per month. However, if the cost of poles, conduit, lines, and transformers are treated as demand rather than customer related, this estimate drops to $10.18 per month. (OTS-RS-4D) But, even this estimate overstates the <u>maximum</u> cost that might be reasonably recovered through a customer charge because it includes the RS class share of uncollectibles and "customer assistance" expense.

Q. WHY IS IT INAPPROPRIATE TO RECOVER UNCOLLECTIBLE EXPENSE THROUGH THE CUSTOMER CHARGE?

A. PP&L's exposure to uncollectible expense depends on the size of a customer's bill. It therefore relates more closely to usage than it does to the existence of a customer.

Q. WHY SHOULD CUSTOMER ASSISTANCE .(ACCOUNT 908) EXPENSES BE EXCLUDED FROM THE CALCULATION OF CUSTOMER COSTS?

A. Based on PP&L's responses to OSBA-30 and CEPFOD-11, the following expenses are included in Account 908.

DSM costs	$12.952 million
Low income assistance	4.373
Other	742
Total	$18.067 million

Mr. Kleha classifies all of these costs as customer related, and allocates them among classes based on customer count. The cost of low income assistance programs such as WRAP would be more appropriately classified as a general overhead, and I see no basis for classifying DSM expenses as a customer cost. According to PP&L:

> Demand Side Management (DSM) programs are intended to promote the most effective use of electricity. DSM programs are designed to change the usage of electricity on the customer's side of the meter in an attempt to alter load shape and reduce utility costs. DSM programs encourage energy efficiency, provide rate options for load shaping flexibility, and encourage the use of electricity to improve efficiency and productivity. A reduction in the growth of the summer and winter peaks may help to defer the need for the additional generation and helps keep overall rates lower. (OTS-RE-46D)

DSM costs are demand and energy rather customer related costs. However, regardless of how these costs are classified and allocated, they should not be included among the costs recovered through a monthly customer charge.

Q. WHAT EFFECT DOES EXCLUDING UNCOLLECTIBLES AND CUSTOMER ASSISTANCE EXPENSE HAVE ON RS CUSTOMER COSTS?

A. Exclusion of these expenses lowers PP&L's adjusted estimate of monthly RS customer cost from $10.18 to about $8.00 per customer.

Q. IF THE ADJUSTMENTS THAT YOU RECOMMEND IMPLY A MONTHLY RS CUSTOMER COST OF $8.00, WHY DO YOU FIND MR. KASPER'S PROPOSED CUSTOMER CHARGE UNREASONABLE?

A. In a different context (revenue spread), Mr. Kasper has opined that strict adherence to the results of a class cost of service study may be inappropriate.

> Following such a simple rate design philosophy does not consider the issues of value of service, social objectives, and market risk. Therefore, it is appropriate to consider the customer impact of the rate increase allocation in light of these issues. (OTS-RS-7D)

An RS customer charge of $7.20 may be technically supported by costs, but an increase in the RS customer charge from $4.80 to $7.20 is inappropriate because of the relatively large affect that it would have on bills for small RS customers, and the tendency for high customer charges to dilute a customer's incentive to conserve. A customer charge that exceeds out-of-pocket expenses conveys no useful information to consumers.

Residential customers have no practical alternative to taking electric service from PP&L. It is therefore meaningless to ration residential access to electricity service. Customers do face decisions regarding the amount of electricity used, and efficiency of use. A high customer charge dilutes the incentive to conserve that the energy charge provides. An increase in the current RS customer charge from $4.80 to $5.80 would permit PP&L to more than recover out-of-pocket customer costs, preserve existing incentives to conserve, and provide a more reasonable sharing of the burden of a rate increase among RS customers.

Q. WHAT IS PP&L'S JUSTIFICATION FOR A DECLINING BLOCK RS RATE STRUCTURE?

A. According to PP&L's response to OCA III-22, the purpose of the proposed declining block structure is to recover "the balance of fixed customer costs" that are not recovered through the RS customer charge. However, this justification is valid only if the Commission approves a customer charge that is significantly less than the $7.20 proposed by PP&L. Even in this case, the differential between the initial and tail block should recover no more than the difference between actual customer costs and the customer charge. For example, if the Commission were to approve an RS customer charge of $5.80 per month, and an energy charge that is blocked at 200 kWh, the corresponding tail block differential would be $.01 per kWh.

Q. IS THERE ANY OTHER JUSTIFICATION FOR A DECLINING BLOCK RS RATE STRUCTURE?

A. Information regarding the load characteristics of small, medium, and large residential customers is not available. (CEPFOD 24) However, some insight can be gained regarding these characteristics by piecing together information regarding the contribution of space heating customers to RS peak demand and energy usage.[8]

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[8] The estimates shown in Table 10 are based on PP&L responses to OCA III-18 (12 CP) and OTS-RE-45D (customer count and average demand).

Table 10

	RS Class (kW)	
	Total	Heating
Average demand per customer	.86	2.23
Twelve CP peak per customer	1.34	3.23
12 CP Load factor	63.8%	68.9%

If customer responsibility for peak demand is measured on a 12 CP basis and the higher demands that space heating customers impose on PP&L's distribution system are ignored, load factor differences among RS customers do not support a widening of the current $.0196 tail block discount, or the three block RS structure proposed by PP&L.[9]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE STRUCTURE OF THE RS ENERGY CHARGE?

A. PP&L has provided no evidence that supports a widening of the existing tail block differential, or the introduction of a third block in the energy change for RS service. I recommend no change in the existing differential of $.0196 per kWh for RS usage in excess of 200 kWh per month.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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9 Demand related production and transmission costs account for about 50% of RS revenue requirement net of customer related cost. If distribution costs per kWh for space heating customers are assumed to be equal to the RS class average, a tail block discount of about $.014 per kWh would be justified by the higher space heating load factor indicated in Table 10.

Class Cost of Service: Residential
(000 Omitted)

	System	RTS		RS	
Customer related distribution per PP&L		3,752		224,150	
Adjusted per OTS-RS-4D		2,473		130,344	
Difference		1,279		93,806	
Allocation Factors:					
Customer		0.01185		0.86861	
Demand		0.04438		0.56875	
Difference		0.03253		-0.29986	
Multiplier		2.74443		-0.34522	
Cost change		3,510		(32,383)	
Rev Requirement per PP&L	2,461,957	42,177		1,065,767	
A&G	149,436	2,515	0.0168	72,416	0.4846
Payroll related (Account 926)	(66,373)	(1,117)		(32,164)	
Fuel	431,704	5,471	0.0127	153,338	0.3552
Purchased Power	252,511	3,252	0.0129	89,959	0.3563
Gross Receipts Taxes	109,928	1,892	0.0470	47,491	0.0466
Net	1,584,751	30,165		734,727	
Reclassify distribution		3,510		(32,383)	
Adjusted PTDC Costs	1,584,751	33,675	0.0212	702,344	0.4432
Reallocated A&G		367		(3,439)	
Incremental Gross Receipts Taxes		182		(1,671)	
Adjusted cost of service		46,236		1,028,274	
Adjusted minus PP&L		4,059		(37,493)	
Current revenues		19,774		887,112	
Required increase		133.82%		15.91%	
PP&L Deficiency		22,403		178,665	
Adjusted Deficiency		26,462		141,172	

Appendix

Qualifications

STEVEN ANDERSEN, PhD
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SUMMARY OF QUALIFICATIONS	Independent consultant. Expert testimony before regulatory agencies and state courts with respect to cost allocation, rate design, capacity expansion planning, financial planning, revenue requirements and asset valuation.
EDUCATION	Ph.D., Economics, October 1972, Rutgers University, New Brunswick, New Jersey. Areas of Specialization: Public regulation, industrial organization, econometrics.
	B.A., Economics, January 1968, The City College, New York, New York.
EXPERIENCE	
1975 - Present	CONSULTANT to industry, state and local governments. Expert analysis and testimony regarding utility rates, property valuation and the economics of local government services.
1983 - 1989	OFFICE OF PUBLIC UTILITY COUNSEL, AUSTIN, TEXAS
	Chief Economist: Direct and supervisory responsibility for economic, financial and accounting analysis affecting the revenue requirements and rates of electric and telephone utilities in the state of Texas. Developed testimony pertaining to cost allocation, rate design, CWIP, cost and revenue annualization, capacity expansion planning, financial planning and purchased power expense.
1979 - 1983	OFFICE OF PUBLIC COUNSEL, JEFFERSON CITY, MISSOURI
	Chief Economist: Essentially the same duties and responsibilities as above regarding electric and telephone utilities and natural gas distribution companies.
1973 - 1981	DEPARTMENT OF ECONOMICS, STATE UNIVERSITY COLLEGE, OSWEGO, NEW YORK
	Assistant Professor: Responsible for teaching and research in the areas of regulatory economics, industrial organization, managerial economics and economic theory. Tenured May 1979. On leave June 1979 to August 1981.
1972 - 1973	DEPARTMENT OF ECONOMICS, RUTGERS UNIVERSITY, NEW BRUNSWICK, NEW JERSEY
	Lecturer: Introductory and intermediate economic theory.

1971 - 1972	THE BROOKINGS INSTITUTION, WASHINGTON, D.C. Research Fellow: Regulatory research pertaining to the economic impacts of air transport regulation.
ACADEMIC FELLOWSHIPS	SUNY Research Fellowship, Summer 1978 Brookings Research Fellow, Sept. 1971 to Aug. 1972 NDEA Fellow, Rutgers University, Sept. 1968 to Aug. 1971
PUBLICATIONS	Andersen, Steven. "Capital Substitution in Electric Utility Cost Allocation," Public Utilities Fortnightly, Vol. 119, No. 4, February 19, 1987. Cicarelli, James and Steven Andersen. "Screening Students for the Principles Courses," Journal of the New York State Economics Association, XII, 1982. Andersen, Steven and J. David Bowman. "Economies of Scale in the Provision of Highway Service by Small Governmental Units," Journal of the New York State Economics Association, XI, 1981. Andersen, Steven. "Investment Behavior in Regulated Industries: Air Transport," International Journal of Transport Economics, V:1, April 1978. Andersen, Steven, J. David Bowman and Lawrence Goss. An Analysis of Public Services Provided by Towns of the Tug Hill Region, Report No. 7, The Cooperative Tug Hill Planning Board, 1976.
PROFESSIONAL PRESENTATIONS	Panelist, 1991 Annual Meeting of NASUCA (Regulation and Economic Development) Lecturer, University of Texas Regulatory Institute: "Fundamentals of Utility Regulation" (Electric Utility Cost Allocation and Rate Design), June 1989. Panelist, 1987 Annual Utility and Ratemaking Conference, Texas Society of Certified Public Accountants. "Economies of Scale in the Provision of Highway Service by Small Governmental Units," Atlantic Economic Conference, Fall 1977, with J. David Bowman. "Market Structure and the Productivity of Investment in Research," Eastern Economics Association Annual Meeting, Spring 1976.

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